





PG&E 10-Year (2028-2037) Electrical Undergrounding Plan

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PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 1

INTRODUCTION, OVERVIEW, AND BASIC INFORMATION

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 1
INTRODUCTION, OVERVIEW, AND BASIC INFORMATION

A. Introduction

Pacific Gas and Electric Company (PG&E) presents our 10-Year Electrical Undergrounding Plan (EUP) to the Office of Energy Infrastructure Safety (Energy Safety). Our EUP describes our framework to select overhead circuit segments to be undergrounded in Tier 2 or Tier 3 High Fire Threat Districts (HFTD) or Fire Rebuild areas. The remainder of this chapter is organized as follows:

- Section B provides an Executive Summary;
- Section C summarizes the background regarding PG&E's wildfire mitigation programs and the EUP;
- Section D provides an overview of risk reduction, program benefits, and customer affordability;
- Section E includes basic information required by Section 2.2 of the EUP Guidelines;[1]
- Section F provides a summary of EUP requirements and identifies the location of responsive information throughout the EUP; and
- Section G lists supporting attachments.

B. Executive Summary

PG&E's EUP is designed to deliver meaningful, long-term benefits for our customers, communities, and the broader public by improving safety, reliability, affordability, and resilience in the face of growing wildfire risk. Undergrounding virtually eliminates wildfire risk and keeps our communities safe in the locations where it is most needed, providing a targeted and durable solution for the highest-risk areas. Our EUP provides significant, quantifiable, and meaningful benefits including:

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[1] Office of Energy Infrastructure Safety, 10-Year Electrical Undergrounding Plan Guidelines (Feb. 20, 2025) (EUP Guidelines).

- **Greater safety for customers and communities:** Wildfire risk continues to increase as weather events become more frequent and severe, reinforcing the need for long-term investments that deliver lasting risk reduction. The EUP will protect communities by undergrounding 5,000 miles of electric distribution lines in the highest-risk areas, permanently reducing wildfire risk by approximately 98 percent where undergrounding has taken place and lowering total Wildfire and Outage Program Risk by approximately $117 billion over the life of the assets.[2]
- **Fewer outages and improved reliability:** Customers benefit from a safer, more reliable electric system as undergrounding can eliminate the need for Public Safety Power Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS) on underground lines and has been shown to reduce outages by approximately 90 percent where undergrounding has been completed.
- **Lower costs and improved affordability:** The EUP will help reduce undergrounding costs over time by leveraging economies of scale and innovation through long-term planning and program development, including new installation methods and more efficient sourcing and contracting. The EUP prioritizes the most cost-effective solutions by comparing undergrounding with other system hardening mitigations so customers benefit from the most efficient investments. Since 2018, we have reduced the cost of undergrounding per mile by approximately 25 percent through innovation and efficiencies. The EUP will facilitate further cost reductions for our critical undergrounding work.
- **Undergrounding benefits exceed customer costs:** The EUP represents capital expenditures of approximately $11.4 billion[3] to install

---

2 $117 billion is the present value of the combined measure of Ignition Risk and Outage Program Risk over the 55-year underground asset life. This measure applies a risk scaling factor and is based on unmitigated wildfire risk, which assumes operational mitigations such as EPSS and PSPS are not in place. Consistent with Energy Safety's requirements, PG&E will report compliance metrics throughout the plan using the unscaled, mitigated baseline described in Chapter 1 Section D, Chapter 2 Section C, and Chapter 7, Core Capability 6 (Establishing and Updating the Baseline).

3 $11.4 billion is the present value of the estimated capital expenditure costs for 5,000 underground miles from 2028 to 2037. This is equivalent to approximately $16.6 billion in escalated capital expenditures.

5,000 underground miles, delivering total, permanent risk reduction benefits of approximately $117 billion. These benefits are approximately ten times the capital cost of undergrounding the proposed miles.

- **Reduced ongoing operating costs and infrastructure investments:** Customers will also benefit from reduced operations and maintenance costs for underground assets by approximately $1.5 million per mile (or $6.0 billion total),[4] as underground facilities are less exposed to vegetation, weather, and many other sources of infrastructure damage that drive maintenance and replacement costs for overhead facilities.
- **Lower wildfire-related losses and costs for our communities:** The EUP reduces the economic impacts of wildfire by reducing:
  - Systemwide, permanent wildfire risk by approximately $105 billion;[5]
  - Average annual utility infrastructure losses by approximately $83 million;[6]
  - Average annual losses from utility-reportable wildfires by approximately 21 percent for residential and commercial customers;[7] and
  - Homeowners' insurance premiums, which are estimated to be reduced by insurers as a result of reducing wildfire risk through undergrounding.[8]

Our EUP is based on extensive analyses to target and select undergrounding projects in areas of highest wildfire risk. We describe our framework for prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. We also include timelines for completing prioritized undergrounding projects along with unit cost targets and mileage completion forecasts for each year of the EUP. We compare the substantial benefits of undergrounding to other system hardening

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4 Avoided costs are presented based on expected O&M savings over the 55-year asset life for each overhead mile removed.

5 $105 billion of wildfire risk reduction is the present value of the monetized, scaled risk over the 55-year asset life, leveraging unmitigated wildfire risk. For reference, the unscaled wildfire risk value, with operational mitigations in place, is calculated as approximately $4.5 billion.

6 Attach. B, WP005 (Marsh, Third Party Impact Analysis of PG&E's 10-Year Undergrounding Plan, September 2026, p. 10).

7 *Id.*, p. ~~3~~4.

8 *Id.*, p. ~~12~~14.

mitigations over the life of the EUP. We also include our plan for utility and contractor workforce development, an evaluation of project costs and projected economic benefits, and plans to reduce undergrounding costs and continue our sustainable supply chain.

The remainder of this summary provides additional detail regarding the significant, quantifiable, and meaningful benefits of the EUP, as well as the analytical approach that we used to develop the EUP.

1. Achieving Substantial Risk Reduction

PG&E's EUP is designed to achieve the legislative objective[9] of substantially and permanently reducing wildfire risk and improving electrical reliability by replacing the highest-risk overhead distribution lines with underground infrastructure. The proposed portfolio will install approximately 5,000 miles of underground distribution facilities, replacing approximately 4,000 miles of overhead distribution lines located in Tier 2 and Tier 3 High Fire Threat Districts and Fire Rebuild areas. Over the 55-year life of the underground assets, the EUP is expected to reduce total Wildfire and Outage Program Risk by approximately $117 billion,[10] including approximately $105 billion in wildfire risk reduction[11] and more than $12 billion in outage program risk reduction.[12] The scale of the proposed EUP reflects PG&E's assessment of the level of undergrounding necessary

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9 Pub. Util. Code, § 8388.5(d)(2).

10 This total Wildfire and Outage Program risk reduction value reflects the present value of total risk reduction over the 55-year asset life using a scaled unmitigated baseline. Using an unscaled mitigated baseline, the present value of risk reduction is approximately $15 billion, which is the basis for the Overall Utility Risk reduction calculation. Overall Utility Risk is defined as the combined measure of Ignition Risk (ignition likelihood multiplied by consequence) and Outage Program Risk, representing total wildfire and outage-related risk. This calculation is unweighted and unscaled, consistent with Energy Safety's reporting requirements.

11 This Wildfire Risk reduction value is the present value of the total Wildfire Risk reduction over the 55-year asset life using a scaled, unmitigated baseline. The Wildfire Risk reduction value is $4.5 billion using an unscaled and mitigated baseline.

12 This Outage Program Risk reduction value is the present value of the Outage Program Risk reduction over the 55-year asset life using a scaled unmitigated baseline. The Outage Program Risk reduction is $10.7 billion using an unscaled and mitigated baseline.

to achieve substantial, system-level wildfire risk reduction and improved reliability throughout its service territory.

Key highlights of PG&E'S EUP are shown in Table 1-1 below.

TABLE 1-1:
HIGHLIGHTS OF PG&E'S EUP

Line No.	Topic	Value
1	All HFTD/HFRA Overhead miles in WDRM v4[(a)]	25,709 miles
2	Overhead Circuit Miles Eligible for Undergrounding	8,805 miles
3	Eligible Underground Circuit Miles[(b)]	11,008 miles
4	Proposed Overhead line miles removed	4,000 miles
5	Proposed Underground miles to install	5,000 miles
6	Avoided Vegetation and Operations and Maintenance (O&M) Costs[(c)]	~$6.0 billion
7	Total Wildfire and Outage Risk Reduction (Scaled/Unmitigated)[(d)]	~$117 billion
8	Present value of capital installation costs of undergrounding from 2028-2037 (2028 dollars)	~$11.4 billion

(a) Overhead miles represented in WDRM v4 are based on the configuration of the system as of January 1, 2023 and do not reflect undergrounding installed since that time.

(b) Based on a factor of 1.25 to convert overhead miles removed to underground miles.

(c) Present value of avoided vegetation and O&M costs over the 55-year asset life.

(d) Risk reduction values are 2028 estimates over the lifespan of the assets based on WDRM v4 and Outage Program Risk Model v1 and represent the maximum forecasted risk reduction associated with the proposed EUP portfolio using current model versions.

As shown in Table 1-1, the proposed EUP represents an approximately $11.4 billion[13] present value investment that is expected to generate approximately $117 billion in total Wildfire and Outage Program Risk reduction benefits over the 55-year life of the underground assets, before considering approximately $6 billion present value in avoided vegetation management and operations and maintenance costs. The magnitude of the

[13] $11.4 billion is the present value of the $16.6 billion in nominal capital expenditures for 5,000 underground miles from 2028 to 2037.

anticipated risk reduction substantially exceeds the cost of the proposed investment, with the expected cost of the EUP representing less than ten percent of the monetized value of the risk reduction benefits. As a result, the proposed undergrounding portfolio is expected to provide more than ten dollars in wildfire and reliability benefits for every dollar invested, demonstrating that strategically targeted undergrounding can provide substantial long-term safety, reliability, and affordability benefits for customers in the highest-risk portions of PG&E's electric distribution system.

PG&E identified approximately 8,800 overhead miles that are eligible for undergrounding under the EUP Guidelines, representing approximately 11,000 underground miles after applying standard engineering conversion factors.[14] From this eligible population, PG&E developed a proposed portfolio of approximately 5,000 underground miles that reflects the scale of undergrounding necessary to deliver substantial system-level wildfire and reliability risk reduction while maintaining a practical and executable program over the ten-year planning horizon. In developing the portfolio, PG&E considered wildfire and outage risk reduction potential, construction feasibility, permitting timelines, workforce and contractor availability, customer affordability, and the diverse terrain and geography of its service territory. PG&E also evaluated whether alternative system hardening mitigations could provide a more cost-effective means of reducing risk in particular locations.

The proposed portfolio is estimated to serve approximately 87,000 customer homes and businesses, of which over 1,800 are critical customers including schools, hospitals, and emergency services.[15] Projects will continue to be refined and validated through the Project Acceptance Framework as engineering, permitting, and field conditions are further evaluated.

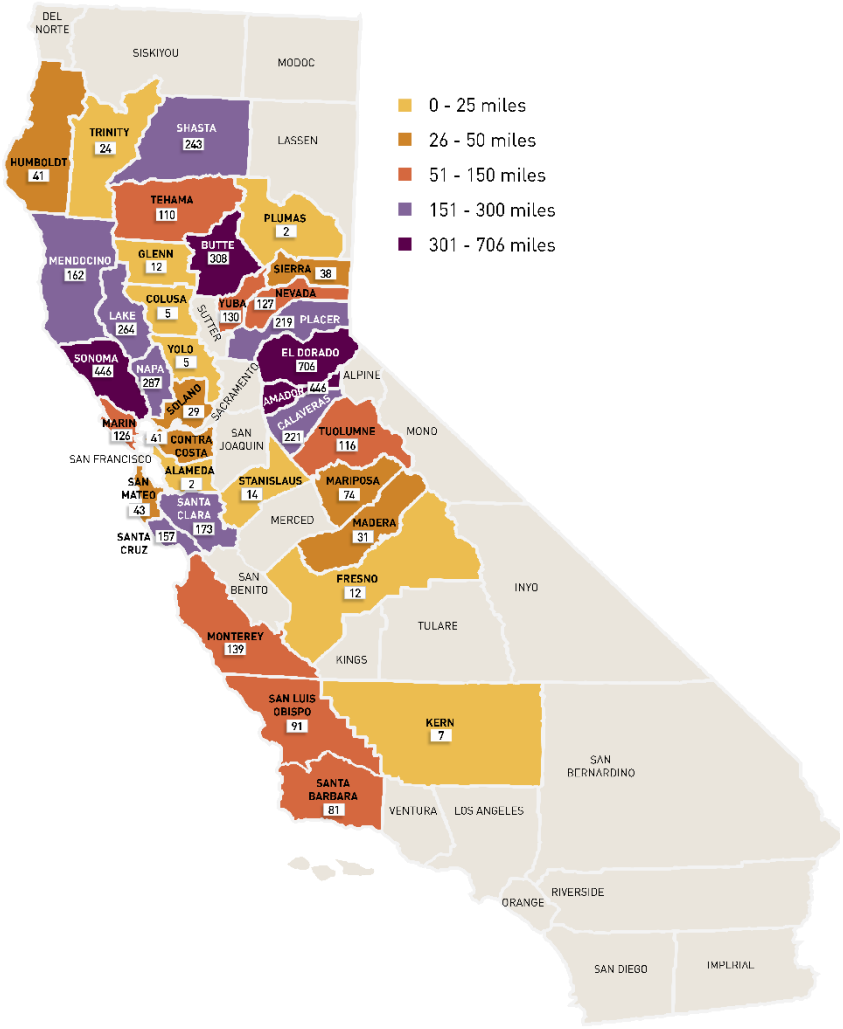
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14 PG&E applies a 1.25 overhead-to-underground conversion factor to reflect that underground installations typically require additional mileage due to rerouting and design constraints, and to provide a standardized approximation for planning, cost estimation, and risk accounting.

15 Customer counts are based on customer data and system configuration based on the latest version of the Wildfire Distribution Risk Model.

Figure 1-1 below illustrates the distribution of proposed EUP undergrounding work across PG&E's service territory.

FIGURE 1-1:
PROPOSED EUP UNDERGROUNDING WORK IN PG&E'S SERVICE TERRITORY



Note: Data as of August 2026. This map is for illustrative purposes. Forecasts represent an estimate of the initial 5,000 highest risk miles to be screened and scoped for PG&E's EUP. Forecasts are preliminary and subject to change due to, but not limited to, project progression through the EUP Project Acceptance Framework, pending regulatory proceedings (EUP with Energy Safety, CPUC Phase 1 and Phase 2 proceedings) and field conditions. Additional miles will be considered as forecasts are matured.

The locations shown in Figure 1-1 represent PG&E's current forecast of the highest-priority undergrounding work identified through its risk-informed planning framework. Forecasts are preliminary and remain subject to refinement as projects progress through the Project Acceptance Framework, regulatory proceedings, permitting processes, engineering development, and field validation activities. Additional qualifying miles may be evaluated and advanced as project forecasts mature over the life of the EUP.

PG&E's EUP achieves these benefits through a data-driven framework that identifies and prioritizes locations with the greatest wildfire and reliability risk. Using the Wildfire Distribution Risk Model, Outage Program Risk Model, benefit-cost analyses, and project-level screening criteria, PG&E has developed a portfolio that focuses investment where undergrounding provides the greatest overall benefit. This framework ensures that PG&E is undergrounding the right facilities in the right locations to deliver substantial and measurable risk reduction for customers and communities.

2. Framework and Models for Selecting the Right Work in the Right Places

PG&E's Project Acceptance Framework provides a structured, risk-based process to systematically identify, evaluate, and prioritize undergrounding projects for the EUP. Through this framework, we derived a targeted portfolio of approximately 5,000 miles of underground distribution lines. The Project Acceptance Framework applies four sequential screens to the full population of circuit segments in PG&E's service territory, progressively narrowing the population to those located in high-fire-risk or Wildfire Rebuild Areas that meet defined risk thresholds, and demonstrate meaningful wildfire risk reduction, public safety, reliability, and cost-efficiency benefits. Through standardized benefit-cost comparisons, project-specific scoping, and refinement of alternative mitigations, we will advance the highest-value projects through the framework and prioritize a final, executable portfolio sized to achieve the Plan Mitigation Objective. The framework also establishes transparent methods for staying up-to-date by incorporating data changes over time, subdividing projects when needed for efficiency and implementation, and sequencing work to maximize portfolio-level risk reduction. The Project Acceptance Framework ensures

that we are undergrounding the right lines in the right places to deliver substantial benefits for the investment.

To implement the framework and meet the analytical requirements, we use a suite of risk models to establish, measure, and monitor the substantial risk reduction achieved through the EUP.

Our integrated, risk-informed modeling framework quantitatively evaluates wildfire risk and electric reliability impacts across the electric distribution system. The framework combines the Wildfire Distribution Risk Model (WDRM), which estimates ignition likelihood and potential wildfire consequences at the circuit-segment level; the Outage Program Risk Model (OPRM), which quantifies customer reliability impacts associated with EPSS and PSPS; and the Wildfire Benefit-Cost Analysis (WBCA), which evaluates lifecycle costs and benefits of system hardening mitigations. Together, these models support consistent, bottom-up portfolio and system-level decision-making, enabling PG&E to identify high-risk locations, evaluate tradeoffs between different mitigation strategies, and account for climate change and uncertainty. Through our modeling, we demonstrate substantial wildfire risk reduction and reliability improvements from these cost-effective investments in the communities we are privileged to serve.

C. Background

California Senate Bill (SB) 884, which was enacted in 2022, requires the California Public Utilities Commission (Commission) to establish a ten-year utility distribution infrastructure undergrounding program for the dual purpose of reducing wildfire risk and reliance on outage programs to mitigate wildfire risk. SB 884 divides responsibility for implementing the program between Energy Safety and the Commission. If a large electrical corporation wishes to participate in the program, they must submit a distribution infrastructure undergrounding plan to Energy Safety. Once submitted, Energy Safety is responsible for review and approval of the utility's plan in compliance with SB 884 requirements for project selection and risk reduction (Phase 1).[16] The Commission is then responsible for approval of the utility's application for cost recovery for SB 884 projects

[16] Pub. Util. Code, § 8388.5(c)(1).

(Phase 2).[17] In Resolution SPD-37, the Commission adopted updated Phase 2 Guidelines and directed the Investor Owned Utilities (IOUs) to submit proposals addressing certain cost recovery issues that remained unresolved, including Benefit Cost Ratio (BCR)[18] methodology, audit methodology, and additional cost recovery conditions.[19]

Since passing SB 884, both Governor Newsom and the California Legislature have continued to emphasize the risks posed to the state by wildfires and the heightened need to reduce those risks and improve resilience. In September 2025, Governor Newsom signed California SB 254 to improve wildfire resilience, lower electricity costs, and accelerate clean energy development. The Legislature found and declared the following urgent climate-driven risks in SB 254:

> (a) Climate change is driving an increase in the frequency and severity of extreme weather events, … including … a significant increase in the incidence and severity of catastrophic wildfires. These extreme weather events impose profound risks to public health, natural resources, infrastructure, and California's economy.
>
> (b) Wildfires [in California] have grown significantly more intense and destructive in recent years….
>
> (c) [C]limate change has dramatically increased the number of acres in California considered High Fire Risk Areas [HFRA].
>
> (d) Wildfire risk is destabilizing the . . . insurance market, increasing the number of California homeowners who are unable to obtain insurance….[20]

The California Earthquake Authority echoed these climate-driven risks and economic impacts in its April 2026 SB 254 report:

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17 Pub. Util. Code, § 8388.5(e)(1). Cost recovery also includes a Phase 3 review of recorded costs, including audits and reasonableness review of certain program costs prior to recovery from ratepayers.

18 Consistent with Commission terminology, references to "BCR" are synonymous with the term "Cost-Benefit Ratio (CBR)" used in certain Commission guidance documents. See Resolution SPD-37, p. 2 n.3.

19 Issues being addressed in the joint CPUC Phase 1 Application (Application (A.) 26-02-005) include the BCR methodology, audits, and cost recovery.

20 SB 254, Ch. 119 (2025-2026 Reg. Sess.), § 1(a-d), available at: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202520260SB254 (accessed June 4, 2026).

> [T]he fire problem the [Western US] faces today is not the historical norm. Climate change is producing hotter, drier conditions, compressing precipitation into shorter windows, and extending the period each year during which fire ignites readily and resists suppression. These shifts, compounded by a century of fuel accumulation in fire-adapted landscapes and decades of development in the wildland-urban interface (WUI), have driven a sharp increase in the frequency and destructive scale of wildfire events across the West. The speed and spread of fires is increasing, and so is the risk of damage. Recently, no state has felt more of that impact than California….[21]

The report highlights the harm experienced by communities and survivors of wildfires. It also addresses the upending of the state's property insurance markets. In the report, the California Earthquake Authority calls for urgent actions by the utilities, communities, and State to reduce wildfire risks. It warns of the cost of inaction in the face of growing risk, stating:

> …[t]he risk is not static; it will not reduce without intervention; it will continue to grow. Deciding not to intervene to reduce the growing risk is thus the knowing acceptance that more California homes and lives are placed at risk with each passing month and year.[22]

PG&E's EUP is one part of our response to urgently address some of the highest wildfire risk areas as called for by the California Earthquake Authority and the Legislature.

D. Risk Reduction and Other Benefits

Undergrounding the highest risk circuit segments in PG&E's service territory is the best solution to address wildfire risk, which is increasing in both frequency and severity. Undergrounding primary electric distribution lines permanently reduces wildfire risk by approximately 98 percent in that location.[23] The benefits of undergrounding, including permanent wildfire risk reduction, reliability improvement, and operational cost avoidance (e.g., less vegetation management), make it the best long-term investment for customers and communities in many high wildfire risk areas.

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21 California Earthquake Authority, Enhancing California's Resiliency to Natural Catastrophes, SB 254 (2025) Study Report (Apr. 7, 2026), p. 17.

22 *Id*., pp. 33-34.

23 See Attach. B, WP001 (Mitigation Effectiveness Analysis).

1. Substantial Wildfire Risk Reduction

In SB 884, the Legislature identified wildfire risk reduction as a central objective of the EUP and requires a utility to demonstrate that its plan will substantially reduce wildfire risk and substantially improve electrical reliability. Specifically, Energy Safety may approve an EUP only if the utility demonstrates that the plan will substantially increase electrical reliability by reducing the use of PSPS, EPSS, de-energization events, and other outage programs, while also *substantially reducing wildfire risk.*[24]

Since 2018, PG&E's wildfire mitigation strategy has combined permanent system hardening measures, including undergrounding, with operational mitigations such as PSPS and EPSS to reduce wildfire risk during periods of elevated fire danger. While operational mitigations provide important layers of protection, they complement but not replace long-term infrastructure investments. As undergrounding projects are completed, the need for PSPS decreases because underground infrastructure is substantially less susceptible to the ignition mechanisms that affect overhead electric facilities.

The Commission has repeatedly emphasized that PSPS should be treated as a mitigation measure of last resort rather than a permanent wildfire mitigation strategy and has directed utilities to reduce reliance on PSPS as infrastructure improvements are deployed.[25] PG&E agrees with this policy direction and believes that permanent system hardening measures, including undergrounding, should be prioritized over continued

---

[24] Pub. Util. Code, § 8388.5(d)(2) states "The office may only approve the plan if the large electrical corporation has shown that the plan will substantially increase electrical reliability by reducing the use of public safety power shut off, enhanced powerline safety settings, deenergization events, and any other outage programs, and *substantially reduce the risk of wildfire*. (emphasis added). Section 8388.5(c)(2) requires the utility to include in the EUP: a means of prioritizing Undergrounding Projects based on "*wildfire risk reduction*, public safety, cost efficiency, and reliability benefits." (emphasis added). Further, Section 8388.5(c)(6) requires the EUP to include "[a]n evaluation of project costs, projected economic benefits over the life of the assets, and any cost containment assumptions, including the economies of scale *necessary to reduce wildfire risk* and mitigation costs and establish a sustainable supply chain." (Emphasis added.)

[25] D.21-06-034, p. 61 ("IOUs are expected to rely on PSPS as a wildfire mitigation *measure of last resort*, less as infrastructure improvements are made and as IOUs refine implementation of PSPS overall to be more targeted.") (emphasis added); see also D.19-05-042, p. 69 (PSPS should be considered a mitigation of "last resort.").

reliance on operational mitigations. The Commission further recognized in PG&E's 2023 General Rate Case that increased undergrounding is expected to reduce reliance on both PSPS and EPSS and provide meaningful benefits to customers and communities by avoiding power outages associated with those programs.[26]

Consistent with Energy Safety guidance, PG&E evaluates undergrounding projects relative to a baseline that includes existing operational mitigations such as PSPS and EPSS. This mitigated baseline calculates the incremental benefit of undergrounding relative to current system operations. However, using PSPS and EPSS as a permanent baseline assumption effectively assumes that those outage programs will remain in place indefinitely. Such an assumption understates the long-term value of undergrounding because it compares a permanent infrastructure investment against temporary operational mitigations that the Commission has directed utilities to reduce over time. Further, using this mitigated baseline to select projects discounts the actual wildfire risk reduction value of undergrounding (which permanently reduces wildfire risk) as these temporary operational mitigations should not be relied on in perpetuity.

Accordingly, in addition to the Energy Safety-required analysis, PG&E presents an alternative analysis using a scaled, unmitigated baseline that excludes the impacts of PSPS and EPSS. This analysis is necessary to demonstrate the full magnitude of the permanent wildfire risk reduction and reliability benefits that undergrounding provides and more accurately reflects the objectives of SB 884 to demonstrate that the EUP will substantially reduce wildfire risk and improve reliability.

Table 1-2 compares the results under both approaches. Using Energy Safety's required unscaled mitigated baseline with PSPS and EPSS in place, the proposed EUP produces approximately $15.1 billion in total

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26 D.23-11-069, pp. 291-292 ("PG&E is likely correct that increased undergrounding, especially on the magnitude suggested by PG&E, will result in PG&E's decreased reliance on PSPS and EPSS, as compared to now, for purposes of wildfire mitigation. The *Commission further agrees that decreased use of PSPS and EPSS will benefit ratepayers and the general public because the impacts of PSPS and EPSS on communities is significant*, as these programs cut power over potentially significant periods, leaving customers with no electric service during times of the year when wildfire risk is high.") (Emphasis added.)

Wildfire and Outage Program Risk reduction over the life of the underground assets. Using a scaled, unmitigated baseline that excludes PSPS and EPSS, the risk reduction increases to approximately $117.4 billion (referred to as total Wildfire and Outage Program Risk reduction).

TABLE 1-2:
EUP RISK REDUCTION: UNSCALED MITIGATED BASELINE COMPARED TO SCALED AND UNMITIGATED RISK BASELINE
(BILLIONS OF DOLLARS)

Line No.	Risk Type	Unscaled and Mitigated Risk Reduction	Scaled and Unmitigated Risk Reduction
1	Total Wildfire and Outage Program Risk	$15.1	$117.4
2	Wildfire	$4.5	$104.9
3	EPSS	$6.3	$6.3
4	PSPS	$4.3	$6.2

Note: Amounts shown are the present value over the 55-year asset life.

As Table 1-2 demonstrates, the estimated Wildfire Risk reduction increases from approximately $4.5 billion under an unscaled, mitigated baseline to approximately $104.9 billion under a scaled, unmitigated baseline. This difference reflects both the removal of temporary operational mitigations from the comparison baseline and the application of risk scaling, which appropriately captures the consequences of low-frequency, high-consequence wildfire events. Because undergrounding permanently removes wildfire ignition exposure from targeted facilities, PG&E believes the scaled, unmitigated analysis more fully reflects the long-term wildfire risk reduction benefits of the proposed EUP. PG&E's use of risk scaling is consistent with the CPUC's Risk-Based Decision-Making Framework (RDF) and ensures that catastrophic wildfire consequences are appropriately considered when evaluating safety investments.[27]

[27] PG&E's Cost-Benefit approach, including the use of its risk-scaling function is consistent with CPUC direction in the Risk-Based Decision-Making Framework proceedings. See D.24-05-064 Appendix A, p. A-8, Row 7; D.22-12-027, Appendix A, p. A-8, Row 7.

2. Performance Targets

Table 1-3 presents the key performance targets for PG&E's EUP using EPSS and PSPS operational mitigations active as required by Energy Safety. All values represent Plan Tracking Objectives for the ten-year duration of the EUP.

TABLE 1-3:
PROPOSED 10-YEAR PERFORMANCE TARGETS OF PG&E'S EUP
(MILLIONS OF DOLLARS)

Line No.	Metric	Value
1	Total Overall Utility Risk Reduction Target (Unscaled/Mitigated)[(a)]	$581
2	Total Ignition Risk Reduction Target[(a)]	$183
3	Total Outage Program Risk Reduction Target[(a)]	$398
4	Risk Reduced Per Mile Installed	$0.116
5	Plan Mitigation Objective: Risk Reduced per Overhead Mile Deenergized	$0.145
6	Count of Projects that have Completed Screen 3 and Screen 4	360

(a) Risk reduction values represent the aggregate risk reduction achieved over the 2028-2037 EUP period based on WDRM v4 and Outage Program Risk Model v1. Annual risk reductions are calculated in the year projects are completed and placed into service, and the reported values are the sum of these annual reductions. These values include the Risk Model Impact Factor described in Chapter 2.

To monitor progress and confirm that the EUP achieves durable, substantial, system-level risk reduction, we will track and report the EUP progress using transparent metrics, including miles undergrounded, overhead miles deenergized, and ignition and outage program risk reduced.

3. Mitigating the Impacts of Climate Change

Climate change is making California's wildfire conditions more frequent, severe, and destructive, and is expanding high-fire-risk areas. In the face of these growing wildfire risks, proactive investments in mitigation, infrastructure resilience and community preparedness are necessary to

reduce future wildfire impacts.[28] The proposed undergrounding investments materially reduce annual losses attributable to climate change from approximately 7 percent to less than 1 percent by 2037.[29] The benefits of the proposed EUP are even more pronounced for severe wildfire scenarios—reducing climate-driven extreme losses[30] by approximately $1.2 billion and most-extreme losses[31] by approximately $869 million.[32] Thus, in addition to reducing current wildfire risk, these results demonstrate that undergrounding also strengthens system resilience against worsening future wildfire conditions.

Figure 1-2 below illustrates the increased risk of extreme losses (i.e., 1-in-100-year losses) in PG&E's service territory due to forecast climate change impacts from 2028 to 2037. As illustrated, there are ~~15~~13 counties that can expect to see a significant increase in forecasted extreme losses of more than $100 million.

Figure 1-3 illustrates the anticipated reduction in losses from extreme wildfires (i.e., 1-in-100-year losses) by 2037 in PG&E's service territory resulting from the reduction of wildfire risk due to this EUP. Overall, we forecast that 30 counties will see a decrease in extreme losses in areas where PG&E expects to underground overhead lines.

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28 California Earthquake Authority, Enhancing California's Resiliency to Natural Catastrophes, SB 254 (2025) Study Report (Apr. 7, 2026);
California Natural Resources Agency, California Climate Adaptation Strategy, Summary of Projected Climate Change Impacts on California. *https://climateresilience.ca.gov/overview/impacts.html* (accessed July 19, 2026).

29 Attach. B, WP005 (Marsh, Third Party Impact Analysis of PG&E's 10-Year Undergrounding Plan, September 2026, p. ~~7~~9).

30 Extreme loss refers to the 99th percentile worst year (largest financial loss) PG&E can experience. This is also interpreted as the worst year out of 100 simulated years.

31 Most extreme loss refers to the average of all years where losses are worse than the Extreme Loss. This is interpreted as the volatility in the tail-end beyond the 99th percentile.

32 Attach. B, WP005 (Marsh, Third Party Impact Analysis of PG&E's 10-Year Undergrounding Plan, September 2026, p. ~~7~~9).

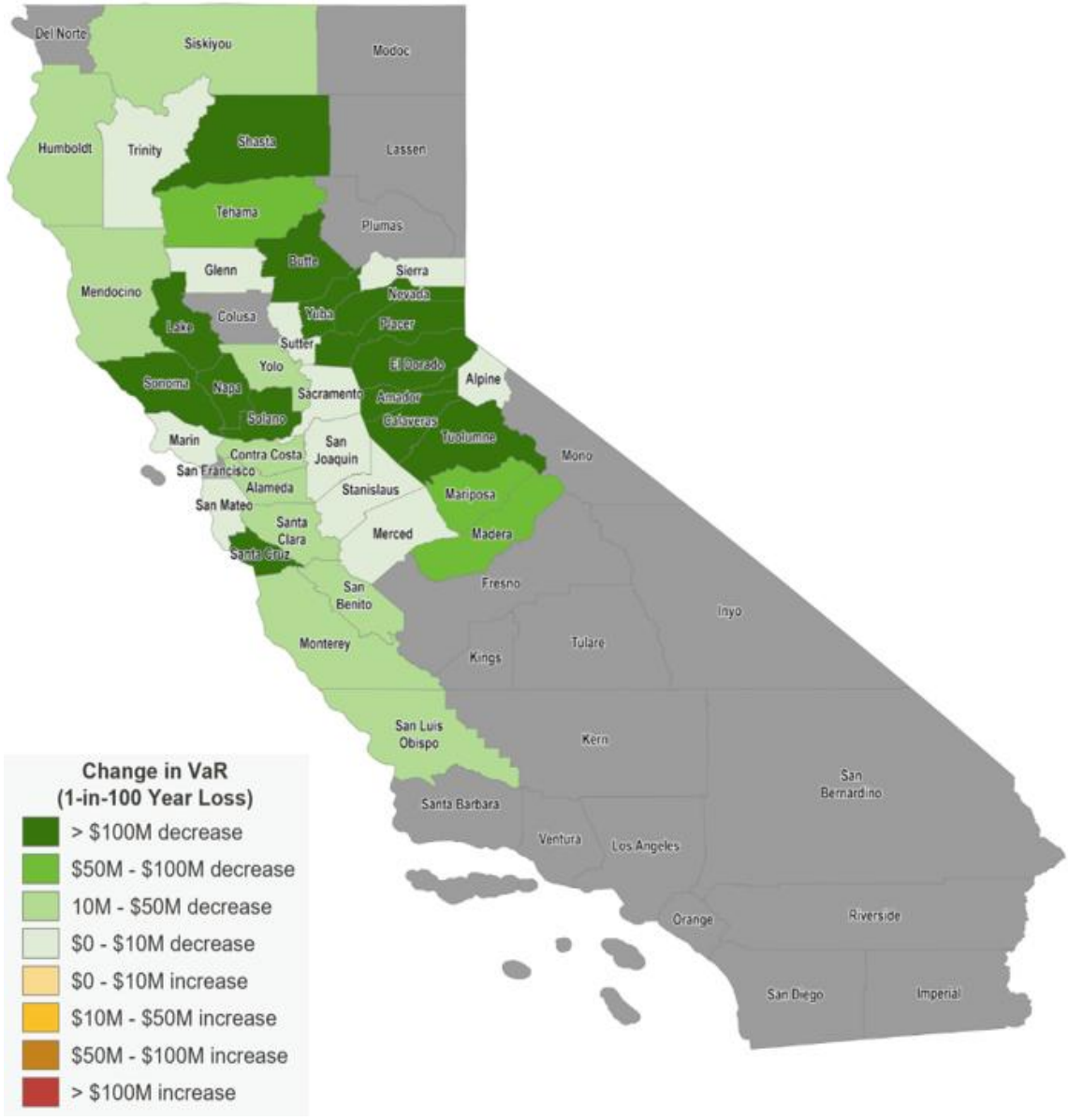
FIGURE 1-2:
CHANGE IN FORECAST LOSSES FROM EXTREME LOSSES IN PG&E'S SERVICE TERRITORY DUE TO CLIMATE CHANGE FROM 2028-2037





Note: 1-in-100 Year VaR is Extreme Loss, defined as the 99th percentile worst year (largest financial loss) that could be experienced. This is also interpreted as the worst year out of 100 simulated years. Attach. B, WP005 (Marsh, Third Party Impact Analysis of PG&E's 10-Year Undergrounding Plan, September 2026, p. ~~7~~9).

FIGURE 1-3:
CHANGE IN FORECAST LOSSES FROM EXTREME LOSSES IN PG&E'S SERVICE TERRITORY DUE TO THE EUP IN 2037 AS COMPARED TO FIGURE 1-2



Note: 1-in-100 Year VaR is Extreme Loss, defined as the 99th percentile worst year (largest financial loss) that could be experienced. This is also interpreted as the worst year out of 100 simulated years. Attach. B, WP005 (Marsh, Third Party Impact Analysis of PG&E's 10-Year Undergrounding Plan, September 2026, p. ~~7~~9).

Given the impacts of climate change, the cost of inaction or less effective mitigations can be substantial. Now is the time to invest in effective, permanent mitigations to prevent future wildfires.

4. Reducing the Severity and Frequency of Utility-Caused Wildfires

From 2014-2024, approximately 81 percent of the losses due to wildfires in PG&E's service territory were attributed to electrical power infrastructure (distribution and transmission systems) even though electrical power infrastructure was the cause of only 9 percent of wildfires.[33] Given the severity of recent fires, the growing threats from climate change and the lasting damage that wildfires cause in our communities, it is imperative that we do everything possible to reduce the likelihood that our infrastructure will cause a wildfire.

The undergrounding work in our EUP, along with overhead hardening and remote grid work and other wildfire mitigation activities presented in our Wildfire Mitigation Plans, will allow us to significantly reduce wildfire risk, reliability risk, and the associated economic losses in our service territory. The EUP will help mitigate significant residential and commercial losses due to utility-caused wildfire risk by approximately 21 percent. See Table 1-4 below for the summary of annual customer losses due to wildfire that would be avoided due to the implementation of our EUP.[34]

TABLE 1-4:
FORECAST OF ANNUAL AVOIDED RESIDENTIAL AND COMMERCIAL LOSSES DUE TO UTILITY-RELATED WILDFIRE FROM 2028 – 2037 DUE TO EUP IMPLEMENTATION

Line No	Type of Losses	Reduction in Losses ($M)	Reduction in Losses (%)
1	Average Annual Losses	$24M	21%
2	Extreme Losses	$533M	20%
3	Most Extreme Losses	$699M	12%

33 Attach B, WP005 (Marsh, Third Party Impact Analysis of PG&E's 10-Year Undergrounding Plan, September 2026, p. ~~3~~4).

34 *Id.*, pp. ~~3~~ 4-~~5~~.

5. Decreasing Losses to PG&E's Distribution Infrastructure

Climate impacts and infrastructure costs are closely linked because changing environmental conditions directly affect both the performance and lifespan of infrastructure assets, while also driving the need for new investments. As climate change increases the frequency and severity of weather-related hazards, it leads to faster equipment degradation, higher failure rates, and reduced asset lifespans, particularly for overhead electric assets exposed to the weather. These physical impacts translate into rising costs through more frequent repairs, increased operations and maintenance expenses, and higher replacement needs for damaged assets. Ultimately this drives significant long-term increases in infrastructure investment and total system costs that must be borne by customers.[35]

PG&E currently faces an estimated average annual loss of $512 million due to damage to our distribution infrastructure caused by wildfires.[36] By 2037, this average annual loss is expected to increase to approximately $584 million or an increase of 14 percent due to climate change.[37] Due to our proposed undergrounding work, we expect our average annual losses to distribution infrastructure from wildfire damage to decrease by approximately $83 million or 17 percent for the remaining lifetime of distribution assets in the HFTD.[38]

6. Continuing the Successful Trajectory of the Undergrounding Program

PG&E's EUP builds on the strong foundation of the Undergrounding Program established through prior General Rate Case (GRC) decisions and reflects years of programmatic learning, innovation, and execution. The Program has matured considerably since its inception — expanding from rebuilding communities affected by wildfire, to proactively hardening facilities across High Fire-Threat Districts (HFTD), and increasingly applying targeted

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35 Fant, et al., Science Direct, Vol. 195, Climate change impacts and costs to U.S. electricity transmission and distribution infrastructure (Mar. 15, 2020), available at: https://www.sciencedirect.com/science/article/pii/S0360544220300062?fr=RR-2&ref=pdf_download&rr=a06930fefc5f1321 (accessed June 4, 2026).

36 Attach. B, WP005 (Marsh, Third Party Impact Analysis of PG&E's 10-Year Undergrounding Plan, September 2026, p. ~~10~~12).

37 *Id.*

38 *Id.*

undergrounding where it delivers the greatest value, such as protecting critical egress routes and addressing elevated tree-strike risk.

As the benefits of undergrounding became increasingly evident, PG&E accelerated this strategy and, in 2021, announced plans to significantly expand undergrounding in HFTDs as a cornerstone of its long-term wildfire mitigation strategy.

The results to date demonstrate both the effectiveness and scalability of the Program. From 2021 to 2027, PG&E will install more than 1,900 miles of underground distribution miles and reduce approximately 14 percent of Ignition Risk[39] in the HFTD and HFRA. In that same time, we have reduced the cost per mile by approximately 25 percent (over $1 million per mile before escalation) through innovation and gaining efficiencies at scale.[40] These achievements provide a strong foundation for the EUP and demonstrate PG&E's ability to deliver substantial risk reduction while continuing to improve program efficiency.

7. Incorporating Affordability into the EUP

We are proud of our Undergrounding Program, the work we have completed, and the efficiencies we have achieved thus far. While undergrounding is the best long-term solution to reduce wildfire risk and significantly reduce outage risk, we also recognize that it should be undertaken in the most appropriate, high-risk areas. Energy Safety has highlighted the importance of cost effectiveness through the EUP requirements for selecting the appropriate mitigation(s) for each circuit segment. In addition, the CPUC, Safety Policy Division (SPD), and Governor Newsom have all stressed the need to carefully balance risk reduction and affordability.[41] In its decision on PG&E's 2023 GRC, the

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39 Value calculated based on the ignition risk reduced from system hardening underground miles using the GRC methodology for calculating risk based on the applicable risk model (i.e. WDRMv2, v3, v4) used to select the projects completed in this period.

40 From 2018-2020, the average unit cost was $4.25 million per mile and from 2023-2025 the average unit cost was approximately $3.25 million per mile.

41 See SPD Evaluation Report on PG&E 2024 RAMP A.24-05-008 (Nov. 8, 2024), p. 82, Recommended solutions to address findings and deficiencies 19; and Governor Newsom's Executive Order N-5-24 (Oct. 30, 2024).

CPUC similarly stated that it was "reasonable to find that ratepayers' ability to pay for safety or risk reduction is not unlimited; as with all safety measures," PG&E, the CPUC, and stakeholders "must consider the cost and impact on affordability."[42]

We agree that affordability is an essential consideration when evaluating risk reduction alternatives. In the highest risk locations, the benefits of undergrounding, including greater wildfire risk reduction, reliability improvement, and operational cost avoidance, ultimately make undergrounding the best investment for customers and communities. PG&E remains focused on keeping our customers and communities safe and providing reliable service at affordable rates, with undergrounding as a key element in delivering that vision.

Our EUP considers affordability by analyzing the potential to use other mitigations, including overhead hardening or remote grid as cost-effective alternatives. PG&E only selects undergrounding where our data and analyses support it as the appropriate mitigation for a particular location. As a result, it is likely that our workplan will include hybrid mitigations—i.e. mitigations including both undergrounding and overhead hardening—on some circuit segments.

As we execute our EUP, we are committed to pursuing a range of cost-containment strategies to reduce undergrounding costs. Our EUP will drive further efficiency through achieving economies of scale and encouraging additional technological and process innovations. PG&E has identified and implemented operational efficiencies through new sourcing approaches and updated construction standards, and implemented waste reduction practices, innovations, and new installation methods. Greater long-term certainty about program funding will allow us to negotiate more favorable pricing with contractors, suppliers, and equipment manufacturers; expand use of fixed-price and optimized contracts; bundle geographically-related work; and build a more levelized, construction-ready pipeline of projects. Further, a stable, multi-year view of projects will improve PG&E's ability to coordinate with communities, counties, and

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42 D.23-11-069, p. 799, Finding of Fact 98.

customers—and to sequence work alongside planned community projects—improving the customer experience.

In addition to reducing the upfront capital costs, PG&E is pursuing opportunities to create efficiencies and reduce costs over the life of the undergrounding assets. For example, undergrounding projects can deliver substantial savings by completing or eliminating the need for previously identified maintenance work as part of project construction; thereby avoiding duplicative work, reducing overall maintenance costs, and minimizing customer impacts. Between 2021 and 2025, undergrounding avoided approximately $72 million in maintenance costs. PG&E expects to realize similar savings with EUP undergrounding projects.

Further, undergrounding is expected to save approximately $1.5 million per overhead mile removed, in long-term operations and maintenance costs when compared to overhead hardening due to the reduced need for maintenance activities such as vegetation management, outage response, and patrols and inspections.[43] PG&E is continuing to work to reduce the cost of both the capital installation and lifetime operations and maintenance costs to support affordability for our customers.

8. Improving System Reliability

Weather-related events such as snow, ice, high winds, flooding, and lightning strikes account for most major power interruptions attributable to electric distribution infrastructure nationwide, causing approximately 78 percent of major outages.[44] This trend is likely to worsen as climate change intensifies weather-related stresses on electric infrastructure in addition to increasing the frequency and cost of outages. PG&E analyzed the reliability performance on sections of circuits where undergrounding

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43 Chapter 5 Section C.3 of the EUP includes further information on the costs and benefits of undergrounding.

44 Fant, et al., Science Direct, Vol. 195, *Climate change impacts and costs to U.S. electricity transmission and distribution infrastructure* (Mar. 15, 2020), available at: https://www.sciencedirect.com/science/article/pii/S0360544220300062?fr=RR-2&ref=pdf_download&rr=a06930fefc5f1321https://www.sciencedirect.com/science/article/pii/S0360544220300062?fr=RR-2&ref=pdf_download&rr=a06930fefc5f1321https://www.sciencedirect.com/science/article/pii/S0360544220300062?fr=RR-2&ref=pdf_download&rr=a06930fefc5f1321 (accessed June 4, 2026).

work was completed and found an approximate 90 percent reduction in sustained outages.[45] While reliability benefits from non-EPSS and non-PSPS outages are not the focus of this EUP, they are expected to be a meaningful, additional benefit of undergrounding for our customers and should not be ignored.

Finally, undergrounding is the most effective means to improve system reliability due to outages caused by PSPS and EPSS. These operational mitigations provide important, temporary layers of wildfire protection across PG&E's system; however, PSPS and EPSS involve tradeoffs with electric service reliability. In 2025, PG&E estimates that these measures resulted in more than 280 million customer minutes interrupted. Where deployed, undergrounding can reduce or eliminate distribution PSPS events and eliminate EPSS-caused outages for those customers.

9. Protecting California Homeowners

Access to property insurance in California's HFTD/HFRA locations has deteriorated significantly in recent years, with insurers electing not to renew policies, restricting new business policies, and some exiting the state entirely.[46] The costs to insure a home in California have increased by over 23 percent from 2017 to 2022,[47] with many in the highest-risk areas being forced into the Fair Access to Insurance Requirements Plan (FAIR Plan) and paying more for coverage that is less comprehensive than standard policies.[48]

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45 PG&E analyzed the reliability performance on sections of circuits where we performed system hardening undergrounding work from 2022 through the end of 2024 to quantify overall improvements to service reliability. PG&E's analysis included approximately 980 outages between 2021 and 2025 and showed an approximate 90 percent reduction in faults that resulted in sustained outages after this undergrounding work was completed.

46 California Earthquake Authority, *Enhancing California's Resiliency to Natural Catastrophes, SB 254 (2025) Study Report* (Apr. 7, 2026), p. 24.

47 UC Berkeley, Center for Law, Energy & the Environment, Costs of Climate Change, Financial and Economic Impacts on California and U.S. Households (Sept. 2025), p. 33, available at: https://www.law.berkeley.edu/wp-content/uploads/archive/2025/09/Costs-of-Climate-Change-Report_CLEE_Sep2025.pdf (accessed June 4, 2026).

48 *Id.*

The increasing risk and losses attributable to wildfire are the primary drivers of increased costs and insurance policy cancellations. By significantly reducing the risk of wildfire associated with utility infrastructure through undergrounding, we are addressing a key driver of the insurance market instability in California. All else being equal, it is estimated that during the 10-year EUP period, the wildfire risk reduction achieved from undergrounding could facilitate a reduction in homeowner insurance premiums for commercially-available insurance plans in our service territory of over 18 percent.[49]

E. Basic Information (EUP Guidelines Section 2.2)

> *The EUP must include basic information about the Large Electrical Corporation, including, but not limited to:*
>
> *a. The legal name of the Large Electrical Corporation.*
>
> *b. The number of customer accounts to show qualification as a Large Electrical Corporation.*
>
> *c. A list of the persons responsible for preparing the EUP, including executive-level owner with overall responsibility; program owners with responsibility for specific components; and the primary contact for Energy Safety and stakeholder general questions. Include names, titles, areas of responsibility, and contact information.*

PG&E's legal name is: Pacific Gas and Electric Company, a subsidiary of PG&E Corporation. PG&E has approximately 5.5 million electric customer accounts and approximately 4.5 million natural gas customer accounts.

A list of persons responsible for preparing the EUP and their contact information is included in Table 1-5 below.

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[49] Attach. B, WP005 (Marsh, Third Party Impact Analysis of PG&E's 10-Year Undergrounding Plan, September 2026, p. ~~12~~14.)

TABLE 1-5:
PERSON(S) RESPONSIBLE FOR EUP BY CHAPTER

Line No.	Section	Chapter Owner(s)	Title	Role	Contact Information
1	Chapter 1: Executive Summary	Matt Pender	Vice President, Undergrounding and System Hardening	Executive-Level Owner for EUP and Undergrounding Program	Matthew.Pender@pge.com
2	Chapter 2: Demonstration of Substantial Risk Reduction	Justin Sadler	Sr. Director, Undergrounding Program	Undergrounding Risk and Execution Strategy	Justin.Sadler@pge.com
3	Chapter 3: Project Acceptance Framework	Justin Sadler	Sr. Director, Undergrounding Program	Undergrounding Risk and Execution Strategy	Justin.Sadler@pge.com
4		Andrea Brown	Director, Electric Risk Management	Wildfire Risk Analytics	Andrea.Brown@pge.com
5		Jon Eric Thalman	Senior Director, System Performance & Reliability	Undergrounding Standards and Asset Strategy	JonEric.Thalman@pge.com
6	Chapter 4: Circuit Segment Information Lists	Justin Sadler	Sr. Director, Undergrounding Program	Undergrounding Risk and Execution Strategy	Justin.Sadler@pge.com
7		Andrea Brown	Director, Electric Risk Management	Wildfire Risk Analytics	Andrea.Brown@pge.com
8	Chapter 5: Timelines, Workforce Development, Costs and Benefits, and Non-Ratepayer Funding Sources	Justin Sadler	Sr. Director, Undergrounding Program	Undergrounding Risk and Execution Strategy	Justin.Sadler@pge.com
9		JP Dolphin	Sr. Director, Economic & Project Analysis	Third Party Funding	John-Peter.Dolphin@pge.com

TABLE 1-5:
PERSON(S) RESPONSIBLE FOR EUP BY CHAPTER
(CONTINUED)

Line No.	Section	Chapter Owner(s)	Title	Role	Contact Information
10	Chapter 6: Progress Report 0	Justin Sadler	Sr. Director, Undergrounding Program	Undergrounding Risk and Execution Strategy	Justin.Sadler@pge.com
11	Chapter 7: Risk Modeling Methodology	Justin Sadler	Sr. Director, Undergrounding Program	Undergrounding Risk and Execution Strategy	Justin.Sadler@pge.com
12		Andrea Brown	Director, Electric Risk Management	Wildfire Risk Analytics	Andrea.Brown@pge.com
13		Yumi Oum	Director, Enterprise and Operational Risk	Enterprise Risk Analytics	Yumi.Oum@pge.com
14	Chapter 8: Model Retention and Update Schedule	Justin Sadler	Sr. Director, Undergrounding Program	Undergrounding Risk and Execution Strategy	Justin.Sadler@pge.com
15		Andrea Brown	Director, Electric Risk Management	Wildfire Risk Analytics	Andrea.Brown@pge.com
16	Chapter 9: Reporting Metrics	Justin Sadler	Sr. Director, Undergrounding Program	Undergrounding Risk and Execution Strategy	Justin.Sadler@pge.com

Questions about any aspect of our EUP should be addressed to: EUPinfo@pge.com.

F. Undergrounding Plan Requirements

PG&E's EUP is designed to meet the EUP requirements in both SB 884 and the EUP Guidelines.

Our EUP is coordinated with the Phase 1 Joint IOU Application pending before the CPUC[50] and the forthcoming Phase 2 CPUC Application where we will seek cost recovery for the approved EUP. These filings are interdependent, particularly with respect to the BCR methodology that aligns with the CPUC's Risk-Based Decision-Making Framework (RDF) and associated data reporting requirements. PG&E has endeavored to develop this EUP consistent with the Commission's regulatory guidance, including the cost recovery framework established in CPUC Resolution SPD-37, the SPD 37 data reporting requirements[51] and the BCR methodology approved in Decisions 22-12-027 and 25-08-032.

Tables 1-6 and 1-7 below identify each statutory and EUP Guidelines requirement for approval of a EUP[52] and indicate where each requirement is addressed in PG&E's EUP.

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50 A decision on the Joint IOU Application (A.26-02-005) is expected to be issued in November 2026.

51 Attach. D (SPD-37 Appendix 1 Data Submission).

52 The Public Utilities Code also includes statutory requirements for activities *following* the approval of an EUP. (See Pub. Util. Code, §§ 8388.5 (e) and (f).) These activities are not listed below or in the tables included the following chapters as they are not required for approval of an EUP by Energy Safety.

TABLE 1-6:
SB 884 STATUTORY REQUIREMENTS

Line No.	Public Utilities Code	Requirement	Where Requirement is Addressed
1	8388.5(c)(1)	10-year plan for undergrounding distribution infrastructure.	Chapters 1-9
2	8388.5(c)(2)	Identification of the undergrounding projects that will be constructed as part of the program, including a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. Only undergrounding projects located in Tier 2 or Tier 3 HFTD or rebuild areas may be considered and constructed as part of the program.	Chapter 3 and Attachment A-2, Table C.4
3	8388.5(c)(3)	Timelines for the completion of identified and prioritized undergrounding projects and unit cost targets and mileage completion targets for each year covered by the plan.	Chapter 2 and Attach. B, WP002 (EUP Target / Timeline Table)
4	8388.5(c)(4)	A comparison of undergrounding versus above ground hardening of electrical infrastructure and wildfire mitigation for achieving comparable risk reduction or any other alternative mitigation strategy, such as covered conductor and rapid earth fault current limiter devices, for those prioritized undergrounding projects, evaluating the scope, cost, extent, and risk reduction of each activity, separately and collectively, over the duration of the plan. The comparison shall emphasize risk reduction and include an analysis of the cost of each activity for reducing wildfire risk, separately and collectively, over the duration of the plan.	Chapters 3 and 7
5	8388.5(c)(5)	A plan for utility and contractor workforce development.	Chapter 5
6	8388.5(c)(6)	An evaluation of project costs, projected economic benefits over the life of the assets, and any cost containment assumptions, including the economies of scale necessary to reduce wildfire risk and mitigation costs and establish a sustainable supply chain.	Chapter 5
7	8388.5(d)(2)	A demonstration that the plan will substantially increase electrical reliability by reducing the use of PSPS, EPSS, de-energization events, and any other outage programs, and substantially reduce the risk of wildfire.	Chapters 2 and 7
8	8388.5(j)	Each large electrical corporation participating in the program shall apply for available federal, state, and other non-ratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers.	Chapter 5

TABLE 1-7:
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
1	2.2	The EUP must provide basic information about the large electrical corporation.	Chapter 1 introduces PG&E's EUP and provides the required basic information a Large Electrical Corporation submitting an EUP must provide.	Chapter 1, Section E
2	Appendix C	Data Organization and Structure (Progress Report 0)	Appendix C defines the requirements for submitting tabular data. Tabular data corresponds to the spatial data submitted with both the initial EUP filing and all subsequent Progress Reports. All tables are specified within this appendix.	Chapter 1, Attachments A-2 – A-5
3	Various	Other Supporting Workpapers and Information	Other supporting information some required with the filing and others considered as optional. These documents include White Papers on Mitigation Effectiveness, EPSS, and KDMM calculations among several other topics.	Chapter 1, Attachment B
4	2.3	Demonstration of Substantial Risk Reduction	Chapter 2 demonstrates how PG&E's EUP complies with Public Utilities Code Section 8388.5(d)(2)[(a)] by demonstrating that we will substantially increase electrical reliability by reducing the use of PSPS and EPSS de-energization events and substantially reduce the risk of wildfire.	Chapter 2, Section C
5	2.3.1	Plan Mitigation Objective	Establishing a Plan Mitigation Objective that meets the requirements of Section 8388.5(d)(2) including supporting narrative and data demonstrating how we will achieve our Plan Mitigation Objective.	Chapter 2, Section D
6	2.3.2	Plan Tracking Objectives	Developing specific plan tracking objectives that will be used to assess how the Portfolio of projects meets the PMO. The plan objectives and targets will be tracked in all Progress Reports pursuant to Sections 8388.5(f)(3) and 8388.5(g).	Chapter 2, Section E

(a) Unless otherwise noted, all further statutory references are to the California Public Utilities Code.

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
7	2.3.3	Risk Calculation for Non-Undergrounding Projects	Calculating risk reduction for non-undergrounding subprojects to comply with Project Thresholds, Plan Mitigation and Plan Tracking Objectives, and comparative metrics.	Chapter 2, Section F
8	2.3.4	Risk Calculations for Projects Extending Beyond a Confirmed Project Polygon	Addressing the requirements for calculating risk reduction when portions of a circuit segment outside of the Confirmed Project Polygon are added to a project.	Chapter 2, Section G
9	2.3.5	Risk Calculations for Projects in Wildfire Rebuild Areas	Addressing the requirements for calculating risk reduction in wildfire rebuild areas to comply with Project Thresholds, Plan Mitigation and Plan Tracking Objectives and for use in Screen 3 comparisons.	Chapter 2, Section H
10	2.4	Project Acceptance Framework	See sections below.	Chapter 3, Section C
11	2.4.1	Project Progression Through Screens	Illustrates the progression of circuit segments through screens 1 through 4 to identify and prioritize eligible circuit segments for undergrounding.	Chapter 3, Section C.1
12	2.4.2	Incorporating Changes	See sections below.	Chapter 3, Section C.2
13	2.4.2.1	Changes to Circuit Segment Information	Accounting for new information, model version and calibration changes and updates to HFTD maps or new Wildfire Rebuild Areas.	Chapter 3, Section C.2.a
14	2.4.2.2	Subprojects	Describing the decision-making process we will use to determine when to divide a circuit segment into Subprojects.	Chapter 3, Section C.2.b
15	2.4.2.3	Other Anticipated Changes	Addressing anticipated changes to the EUP.	Chapter 3, Section C.3

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
16	2.4.2.4	Physical Changes to a Circuit Segment	Accounting for physical changes to a circuit segment such as relocating lines, adding or removing equipment that redefines circuit segment endpoints, or changes in alignment due to undergrounding.	Chapter 3, Section C.4
17	2.4.3	Screen 1: Circuit Segment Eligibility	Identifying relevant circuit segments and creating the list of eligible circuit segments.	Chapter 3, Section D.1
18	2.4.3.1	Identification of Circuit Segments Inside and Outside of a Tier 2 or Tier 3 HFTD or a Wildfire Rebuild Area	Identifying all circuit segments in PG&E's service territory (all circuit segments) and specifying which circuit segments are in a Wildfire Rebuild Area or Tier 2 or 3 HFTD (In Area Circuit Segments).	Chapter 3, Section D.1.a
19	2.4.3.2	Identification of Risky Circuit Segments and Mitigation Standards	Evaluating the list of In Area Circuit Segments to determine EUP eligibility and minimum mitigation needs.	Chapter 3, Section D.1.b
20	2.4.4	Screen 2: Project Information and Alternative Mitigation Comparison	Confirming there is sufficient information available on a circuit segment and conducting a comparison of undergrounding to alternative mitigations to determine which eligible circuit segments can be treated as Undergrounding Projects.	Chapter 3, Section D.2
21	2.4.4.1	Common Set of Values and Assumptions	Using common values and assumptions to develop estimates for circuit segments when project specific information is not available.	Chapter 3, Section D.2.a

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
22	2.4.5	Screen 3: Project Risk Analysis	Evaluating an individual undergrounding project in the context of the Portfolio of undergrounding projects by considering the wildfire risk reduction and reliability increase of an Undergrounding Project compared to alternative mitigations.	Chapter 3, Section D.3
23	2.4.5.1	Screen 3 Procedure	Process for completing Screen 3.	Chapter 3, Section D.3.a
24	2.4.5.2	Twenty-Five Undergrounding Project Requirement	Submitting a portfolio of at least twenty-five undergrounding projects considered under Screen 3 with our EUP submittal.	Chapter 3, Section D.3.b
25	2.4.6	Screen 4: Project Prioritization and Finalization	Establishing and supporting a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits.	Chapter 3, Section D.4
26	2.4.7	Required Circuit Segment Information Lists	See sections below.	Chapter 4, Section C
27	2.4.7.1	Instructions for Circuit Segment information Lists	Creating progressively smaller sets of circuit segments that satisfy different criteria until they become Confirmed Projects and Prioritized Projects.	Chapter 4, Section C.1
28	2.4.7.2	Information on Non-EUP Projects	Providing information on distribution undergrounding or other system hardening projects in a Tier 2 or 3 HFTD that is funded or in the planning and construction phases outside of the EUP.	Chapter 4, Section D

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
29	2.5	Project Timelines, Workforce Development Plan, Costs and Benefits, and Non-Ratepayer Funding Sources	See sections below.	Chapter 5, Section C
30	2.5.1	Project Timelines and Targets	A comprehensive Target/Timeline framework that specifies annual and cumulative project timelines to transparently plan, track, and report progress across the 10-year horizon.	Chapter 2, Section D.1
31	2.5.2	Workforce Development Plan	Develop a comprehensive workforce development plan that demonstrates how the utility will secure and manage the necessary internal and contractor resources over the 10-year period.	Chapter 5, Section C.2
32	2.5.3	Costs and Benefits	Provide an evaluation of project costs and lifecycle economic benefits, along with cost containment assumptions and strategies to ensure the program delivers cost effective wildfire risk.	Chapter 5, Section C.3
33	2.5.4	Non-Ratepayer Funding Sources	Identify available federal, state, and other non-ratepayer funding sources, demonstrating how these external funds will be integrated into the program to reduce the financial burden on ratepayers.	Chapter 5, Section D
34	2.6	Progress Report 0	Developing and submitting Progress Report 0 which includes narrative, graphs, tabular data, JSON data and GIS data showing the status of circuit segments and other matters related to wildfire and reliability risk reduction at the time we submit our EUP.	Chapter 6, Section C

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
35	2.6.1	Content of Progress Report 0	Preparing and submitting narratives describing PG&E's portfolio coversheet; example rejected project, PMO, plan tracking objective, target/timeline table, identified wildfire rebuild area, alternative mitigation selection, model reports, and all data pursuant to Appendix C.	Chapter 6, Section C.1
36	2.6.2	Relation of Progress Report 0 to Statutory Progress Report Requirement	Acknowledging that content, format, and structure of Progress Report 0 will inform the requirements for future Progress Reports.	Chapter 6, Section C.2
37	2.7	Risk Modeling	Describing the risk modeling requirements that we will use to establish the PMO and to perform the analysis required in Screen 3.	Chapter 7, Section C
38	2.7.1	Overview of Risk Modeling Methodology	Providing an overview of the key elements of our risk modeling approach; detailing how we will compare the wildfire risk reduction and reliability impacts of undergrounding to alternative mitigations; and describing our Risk Assessment Methodology.	Chapter 7, Section C.1
39	2.7.2	Model Reports	Presenting a Model Report describing each individual model used in our Risk Modeling Methodology.	Chapter 7, Section D
40	2.7.3	Key Decision-Making Metrics and Enterprise Diagrams	Listing and describing the five required KDMMs we use to evaluate the efficacy of an undergrounding project.	Chapter 7, Section E
41	2.7.4	Model Risk Landscape	Summarizing the inputs, outputs, and intermediate calculations used in our risk modeling methodology.	Chapter 7, Section F

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
42	2.7.5	Required Core Capabilities for Risk Modeling Methodology	Explaining the quantitative procedures for achieving the seven Core Capabilities. The Core Capabilities are: (1) Project Level Risk Analysis; (2) Aggregate Risk Analysis; (3) Ignition Risk and Outage Program Risk as Separate and Collective Risks; (4) Approximating Future Risks and Accumulation of Ignition Risk and Outage Program Risk Over Time; (5) Accounting for Undergrounding Projects with Multiple Mitigations and Subprojects; (6) Establishing Baselines and Historical Calibrations; and (7) Comparisons with Alternative Mitigation Strategies.	Chapter 7, Section G
43	2.7.5.1	Model Inputs and Considerations	Providing a comprehensive summary of all model inputs used to compute each metric in our Model Risk Landscape.	Chapter 7, Section H
44	2.7.5.2	Version and Calibration Changes	Describing our anticipated schedule for updating our risk models and methods for recording these changes.	Chapter 7, Section I
45	2.7.6	Model Retention and Update Schedule	Describing our model and calibration retention policies and our plan for updating our risk models.	Chapter 8, Section C
46	2.7.7	Project Variable Modifiers (PVMs)	Listing and explaining which input risk modeling variables change and their effect on given project, a set of projects, and KDMMs.	Chapter 7, Section K

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
47	2.7.8	Portfolio-Level Standards	Establishing an Ignition Risk Decrease Standard and Reliability Increase Standard (the Portfolio Standards) that we will use to demonstrate the substantial decrease in ignition risk and substantial increase in reliability per Section 8388.5(d)(2) and will be used to judge the overall efficacy of the EUP.	Chapter 7, Section L
48	2.7.9	Project-Level Thresholds and Standards	Establishing and explaining the Project Level Thresholds (High Risk Threshold, Ignition Tail Risk Threshold, High Frequency Outage Program Threshold, and Mitigated Risk Threshold) using a combination of KDMMs to establish the need for the circuit segment mitigation.	Chapter 7, Section M
49	2.7.9.1	Project-Level Thresholds	Setting and explaining a High-Risk Threshold, Ignition Tail Risk Threshold, and High Frequency Outage Program Threshold to establish the need for mitigation on a circuit segment.	Chapter 7, Section M.1
50	2.7.9.2	Project-Level Standards	Setting and explaining Project Level Standards to determine the necessary level of risk reduction for an undergrounding project to merit inclusion in the EUP.	Chapter 7, Section M.2
51	2.7.10	Comparative Metrics	Comparing each undergrounding project to the required design variations, including an evaluation of at least two comparable Alternative Mitigations.	Chapter 7, Section N

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
52	2.7.6[(a)]	Model Retention and Update Schedule	Schedule for updates to PG&E's Risk Modeling Methodology, the timing and contents of reports on any new models or model updates, backtest of the models on Key Decision-Making Metrics (KDMMs), the establishment of a new baseline, and updates to risk scores for new equipment.	Chapter 8, Section C
53	2.8	Reporting Metrics	See sections below.	Chapter 9, Section C
54	2.8.1	Tabular Data Submission	Providing tabular data tables C.1 through C.15, and C.22 and C.23 reflecting the most current information as of our EUP submittal.	Chapter 6 Section C. 1 Attachment A-2
55	2.8.2	JSON Data Submission	Submitting a PVM and Model Risk Landscape JSON reflecting the most current information as of our EUP.	Chapter 6, Section C Attachments A-3 and A-4
56	2.8.3	Spatial Data Reporting for Projects	Reporting additional modeling and project level data through a geodatabase submission that identifies Circuit Segments, Undergrounding Projects, overhead lines that will be deenergized and critical pieces of infrastructure equipment.	Chapter 6, Section C Attachment A-5
57	2.8.4	Data Validation	Acknowledging that Energy Safety will review and validate data and reject data submissions that do not meet the criteria in EUP Guidelines.	Chapter 9, Section C.4
58	2.8.5	Risk Modeling Methodology Verification Data	Generating a series of numerical and visual elements establishing the veracity of our risk modeling methodology.	Chapter 9, Section C.5
59	2.8.6	Reporting a Portfolio of Undergrounding Projects	See sections below.	Chapter 9, Section D

TABLE 1-7
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS
(CONTINUED)

Line No.	EUP Guidelines Section Number	EUP Guidelines Requirement	EUP Requirement Summary	Where Requirement Is Addressed
60	2.8.6.1	Portfolio Coversheet Overview	Preparing a text document that summarizes the macro-level impacts of the EUP.	Chapter 9, Section E
61	2.8.6.2	System and Portfolio-Level Risk Matrices and Profiles for Key Decision-Making Metrics	Providing a series of visualizations and tables for each KDMM showing the KDMM's distribution with and without the portfolio's modeled mitigation.	Chapter 9, Section F
62	2.8.6.3	Portfolio Development	Describing our system for tracking changes in our portfolio over time.	Chapter 9, Section G
63	2.8.6.4	Portfolio Coversheet Organization	Describing how the Portfolio Coversheet is organized.	Chapter 9, Section H

Note: (a) The EUP Guidelines Appendix B narrative content structure lists Section 2.7.6 in both Chapter 7 and Chapter 8. PG&E addresses Section 2.7.6 requirements in Chapter 8 of our EUP.

G. Chapter 1 Supporting Attachments Index

The following workpapers and data support this chapter.

TABLE 1-8:
CHAPTER 1 SUPPORTING ATTACHMENTS/WORKPAPERS INDEX

Line No.	EUP Section	EUP Location	Workpaper / Table Name	File Name
1	1.D	Attachment B	WP001 (Mitigation Effectiveness Analysis)	PGE_WP001_2026-09-30_Mitigation Effectiveness Analysis_R0
2	1.B 1.D.3 1.D.4 1.D.5 1.D.9	Attachment B	WP005 (Third Party Impact Analysis of PG&E's 10-Year Electrical Undergrounding Plan)	PGE_WP005_2026-~~09~~10-30_Third Party Impact Analysis of PG&E's 10-Year Electrical Undergrounding Plan_R0
3	1.C.2 1.F	Attachment D	SPD-37 Appendix 1 Data Submission	PGE_Initial_2026-~~09-30~~11-02_Attachment D_R0

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 2

DEMONSTRATION OF SUBSTANTIAL RISK REDUCTION

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 2
DEMONSTRATION OF SUBSTANTIAL RISK REDUCTION

A. Introduction

In this chapter, we address the requirements in Section 2.3 of the Electrical Undergrounding Plan (EUP) Guidelines to explain our Plan Mitigation Objective, targets and timeline, Plan Tracking Objectives, and risk calculations

Section B lists the requirements from Senate Bill (SB) 884 and the EUP Guidelines addressed in this chapter.

Section C provides our overarching demonstration of substantial risk reduction. We explain how undergrounding reduces both Ignition Risk and Reliability Risk, using Overall Utility Risk as an integrated, monetized metric. We explain our identification of a Portfolio of approximately 4,000 overhead miles (or 5,000 miles of undergrounding) that meets or exceeds the Plan Mitigation Objective per mile target to reduce an average of $145,000 of Overall Utility Risk per overhead mile per year,[53] which is equivalent to $3 million of risk reduction per mile over the 55-year life[54] of the underground assets.

Section D explains the Plan Mitigation Objective, which is the measure that will show that our execution of the EUP has substantially reduced Wildfire Risk and increased reliability[55] in the High Fire Threat Districts (HFTD) over the ten-year period. The Plan Mitigation Objective is expressed as the monetized value of the Overall Utility Risk reduced per primary overhead mile removed and demonstrates that PG&E's EUP will result in substantial risk reduction.

Section E describes the Plan Tracking Objectives, which are forward-looking, quantifiable metrics used to monitor progress toward

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53 The EUP Guidelines define Overall Utility Risk as "an unweighted and unscaled calculation," Office of Energy Infrastructure Safety, 10-Year Electrical Undergrounding Plan Guidelines (Feb. 20, 2025) (EUP Guidelines), p. 31. For the purposes of operational planning, PG&E uses scaled risk values.

54 This is the present value of the Plan Mitigation Objective ($145,000 per mile of Overall Utility Risk) summed over the 55-year asset life.

55 Reliability will be increased by reducing the use of Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) outage programs.

achievement of the Plan Mitigation Objective over time. In this section, we explain how PG&E will update and compare Plan Tracking Objectives in each Progress Report, including how variances are evaluated and addressed.

Section F explains how risk is calculated and allocated for Undergrounding Projects on Circuit Segments that include non-undergrounding Subprojects, such as Overhead System Hardening or other mitigations. We explain that only the risk reduction attributable to undergrounding is counted toward the Plan Mitigation Objective and Plan Tracking Objectives.

Section G addresses risk calculations for Projects that extend beyond a previously Confirmed Project Polygon. This section explains how we account for changes in Project scope, consistent with the EUP Guidelines.

Section H identifies the other EUP chapters where we explain how we evaluate risk if a Circuit Segment is in a Fire Rebuild area.

Section I provides a brief chapter summary.

Section J includes a list of supporting attachments.

B. Undergrounding Plan Requirements

In Tables 2-1 and 2-2 below, we identify each of the statutory and EUP Guidelines requirements addressed in this chapter.

TABLE 2-1:
SB 884 REQUIREMENTS ADDRESSED IN CHAPTER 2

Line No.	Public Utilities Code Section	Legislative Requirement	Where Requirement is Addressed
1	8388.5(d)(2)	The office [Office of Energy Infrastructure Safety] may only approve the plan if the large electrical corporation has shown that the plan will substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and substantially reduce the risk of wildfire.	Chapter 2 in Totality

TABLE 2-2:
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS ADDRESSED IN CHAPTER 2

Line No.	EUP Guidelines Section	EUP Guidelines Requirements	Requirement Reference in Chapter 2
1	2.3	Demonstration of Substantial Risk Reduction	Section C
2	2.3.1	Plan Mitigation Objective	Section D
3	2.3.2	Plan Tracking Objectives	Section E
4	2.3.3	Risk Calculation for Non-Undergrounding Projects	Section F
5	2.3.4	Risk Calculations for Projects Extending Beyond a Confirmed Project Polygon	Section G
6	2.3.5	Risk Calculations for Projects in Fire Rebuild Areas	Section H

C. Demonstration of Substantial Risk Reduction (EUP Guidelines, Section 2.3)

Pursuant to Section 8388.5(d)(2), the EUP can only be approved if it will (1) "substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs," and (2) "substantially reduce the risk of wildfire." To support this, the EUP must include the Plan Mitigation Objective, Plan Tracking Objectives, and other specific tracking objectives and targets as described below.

Pursuant to Public Utilities Code Section 8388.5(d)(2), the EUP may be approved only if it will (1) "substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs," and (2) "substantially reduce the risk of wildfire." PG&E demonstrates that the EUP satisfies these requirements through the risk reduction achieved by the forecast EUP Portfolio, the Plan Mitigation Objective and Plan Tracking Objectives used to measure and track that risk reduction, and supplemental analysis demonstrating the broader long-term benefits of permanent underground infrastructure.

1. Risk Reduction Under the Energy Safety-Required Methodology

Consistent with the EUP Guidelines, PG&E calculates Overall Utility Risk[56] on an unweighted and unscaled basis relative to a mitigated baseline that reflects existing operational mitigations, including Public Safety Power

[56] The EUP Guidelines define Overall Utility Risk as "an unweighted and unscaled calculation." EUP Guidelines, p. 31. For the purposes of operational planning, PG&E uses scaled risk values.

Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS). Risk reduction is quantified as an integrated, monetized Overall Utility Risk reduced per primary overhead mile removed. PG&E's EUP measures Overall Utility Risk reduction achieved through targeted undergrounding of the highest-risk Circuit Segments by quantifying the monetary value of the reductions in both Ignition Risk[57] and Outage Program Risk.[58] This measure provides the basis for establishing the Plan Mitigation Objective and Plan Tracking Objectives and for reporting progress under the EUP.

Based on the Project Acceptance Framework[59] and risk modeling,[60] PG&E identified a forecast Portfolio of approximately 4,000 overhead miles to be removed and deenergized. Replacing those overhead facilities is expected to require approximately 5,000 underground miles, based on the 1.25 overhead-to-underground conversion factor used for EUP planning. The two mileage values describe the same forecast portfolio: 4,000 miles represents the primary overhead facilities removed, while 5,000 miles represents the corresponding underground facilities installed. The forecast Portfolio includes Circuit Segments that are eligible following Screen 2 and have an undergrounding Benefit-Cost Ratio indicating that they are potential candidates for inclusion in the EUP. Projects will continue to be evaluated, refined, and selected through the remaining stages of the Project Acceptance Framework.

Using the Energy Safety-required unscaled, mitigated methodology, the forecast EUP Portfolio may reduce up to approximately $15.1 billion in present-value Overall Utility Risk over the 55-year life of the underground assets. This total includes approximately $4.5 billion in Ignition Risk reduction and approximately $10.6 billion in Outage Program Risk

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57 Ignition Risk is the measure of impacts from wildfire at a given location. This metric is the product of two factors: (1) the likelihood a wildfire will occur, and (2) the potential consequences of a wildfire originating from this location.

58 Outage Program Risk is the modeled risk associated with customer outages, including impacts from PSPS and EPSS, derived from outage risk modeling.

59 See Chapter 3 for details.

60 See Chapter 7 for details.

reduction.[61] These results demonstrate substantial reductions in both components of Overall Utility Risk under Energy Safety's required methodology.

Undergrounding provides a durable reduction in Ignition Risk by removing targeted overhead facilities and the associated ignition exposure. It also improves reliability by reducing the need to apply PSPS and EPSS to the undergrounded facilities. The magnitude and duration of these reductions demonstrate that the EUP will substantially reduce wildfire risk and substantially increase electrical reliability as required by Public Utilities Code Section 8388.5(d)(2).

2. Plan Mitigation Objective and Plan Tracking Objectives

The Plan Mitigation Objective and Plan Tracking Objectives establish the framework PG&E will use to measure, track, and report the risk reduction achieved through implementation of the EUP.

Energy Safety defines the Plan Mitigation Objective as "the amount of change in risk (wildfire and reliability) that is necessary to meet the requirements of Public Utilities Code Section 8388.5(d)(2)."[62] PG&E's Plan Mitigation Objective is: An annual average reduction of $145,000 in Overall Utility Risk per primary overhead mile removed.

The Plan Mitigation Objective is based on the Energy Safety-required unscaled, mitigated methodology described above. It reflects the combined reduction in Ignition Risk and Outage Program Risk attributable to EUP undergrounding. The annual average reduction of $145,000 in Overall Utility Risk is equivalent to approximately $3 million in present-value Overall Utility Risk reduction per primary overhead mile removed over the 55-year life of the underground assets. More detail about how the Plan Mitigation Objective was developed can be found in Section D.1. below.

The Plan Tracking Objectives establish the annual, five-year, and ten-year milestones PG&E will use to determine whether the EUP remains

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61 This value excludes the Risk Model Impact Factor described in Chapter 2 as described in Section 1.a. below.

62 EUP Guidelines, Glossary, p. A-5.

on track to achieve the Plan Mitigation Objective. More detail about the Plan Tracking Objectives can be found in Section E below.

The Plan Mitigation Objective defines the required risk reduction outcome on a per-mile basis, while the Plan Tracking Objectives provide the interim measures used to monitor progress toward that outcome. Together, the Plan Mitigation Objective and Plan Tracking Objectives provide an outcome-based framework for measuring the wildfire and reliability risk reduction delivered by the EUP.

3. Supplemental Demonstration of the Long-Term Benefits of Undergrounding

The Energy Safety-required unscaled, mitigated methodology provides the basis for establishing and tracking the Plan Mitigation Objective and Plan Tracking Objectives. However, as discussed in Chapter 1, this methodology does not fully reflect the long-term value of replacing overhead facilities with permanent underground infrastructure.

The mitigated baseline assumes that operational mitigations such as PSPS and EPSS remain in place over the life of the underground assets. Although PSPS and EPSS provide important layers of wildfire protection, they result in customer outages and are intended to complement, rather than replace, permanent infrastructure improvements. Comparing undergrounding against a baseline that assumes these operational mitigations remain in place indefinitely therefore understates the long-term benefits of undergrounding and the value of reducing reliance on outage programs.

The unscaled methodology also does not reflect risk aversion to low-frequency, high-consequence wildfire events. PG&E therefore supplements the required analysis with a scaled, unmitigated analysis that removes the effects of PSPS and EPSS from the baseline and applies risk scaling to reflect the consequences of catastrophic wildfire events. This supplemental analysis does not replace the methodology used to establish or track the Plan Mitigation Objective and Plan Tracking Objectives. Instead, it provides additional context regarding the full magnitude of the permanent wildfire and reliability benefits provided by undergrounding.

By replacing 4,000 overhead miles with 5,000 underground miles, under the supplemental scaled, unmitigated analysis, PG&E's EUP will reduce approximately $117.4 billion in total Wildfire and Outage Risk over the 55-year life of the underground assets,[63] of which $104.9 billion is attributed to Wildfire Risk reduction[64] and approximately $12.5 billion is attributed to Outage Program risk reduction.[65] These results demonstrate the broader value of transitioning away from continued reliance on operational mitigations and investing in underground infrastructure that permanently removes targeted overhead ignition exposure and reduces the need for PSPS and EPSS.

Taken together, the two analyses serve distinct but complementary purposes. The Energy Safety-required unscaled, mitigated analysis provides the compliance basis for establishing and tracking the Plan Mitigation Objective and Plan Tracking Objectives. The supplemental scaled, unmitigated analysis more fully demonstrates the magnitude and durability of the EUP's long-term wildfire risk reduction and reliability benefits. Under either analytical approach, the EUP is expected to deliver substantial wildfire risk reduction and substantially improve electrical reliability over the life of the underground assets.

D. Plan Mitigation Objective Requirements (EUP Guidelines Section 2.3.1)

The Plan Mitigation Objective is the total amount of change in risk (wildfire and reliability) that is necessary to meet the requirement of Section 8388.5(d)(2). This change in risk must account for only the reduction due to Undergrounding Projects (see Core Capabilities Section 2.7.5) and be measured on a pro rata basis.

The Large Electrical Corporation must set a Plan Mitigation Objective for the EUP and provide a supporting narrative and data in the EUP demonstrating how the EUP will achieve the Plan Mitigation Objective. In order to achieve the Plan

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63 This total Wildfire and Outage Risk Reduction value is the present value of the total risk reduction over the 55-year asset life using a scaled unmitigated baseline. The Overall Utility Risk reduction value is $15 billion using an unscaled mitigated baseline.

64 This Wildfire Risk reduction value is the present value of the total Wildfire Risk reduction over the 55-year asset life using a scaled unmitigated baseline. The Wildfire Risk reduction value is $4.5 billion using an unscaled and mitigated baseline.

65 This Outage Program Risk reduction value is the present value of the Outage Program Risk reduction over the 55-year asset life using a scaled unmitigated baseline. The Outage Program Risk reduction is $10.7 billion using an unscaled and mitigated baseline.

Mitigation Objective, the Large Electrical Corporation will select projects (consisting of individual isolatable Circuit Segments) during the 10-year EUP.

The narrative must address the following:

a. *Explanation of the basis of the Plan Mitigation Objective.*

b. *The source for the risk and reliability scores used to set the Plan Mitigation Objective.*

c. *Minimum levels of Ignition Risk and Outage Program Risk reduction as set forth in the Portfolio-Level Standards.*

d. *Overview of the implementation approach for the EUP (e.g., to reduce risk on the highest risk Circuit Segments first, or to select the most feasible for Undergrounding first) and an explanation of how the implementation approach will achieve the Plan Mitigation Objective.*

e. *An overview of how the Project Acceptance Framework, project timelines, plan for workforce development, nonratepayer funding, Progress Report 0, Risk Modeling, and Reporting Metrics all support the Plan Mitigation Objective (see Sections 2.4 –2.8 of these Guidelines).*

f. *A concise summary and clear presentation of the metrics and standards for the Portfolio of Undergrounding Projects and supporting Project-Level metrics.*

Instructions for developing and calculating these metrics are found in the Risk Modeling Section 2.7 of these Guidelines.

g. *A summary of how Undergrounding Projects with multiple Subprojects (including any non-undergrounding Subprojects) will be reported and how the amount of risk reduced by these Undergrounding Projects will be allocated between the EUP Undergrounding Subprojects and non-undergrounding Subprojects as described in Section 2.7.5 of these Guidelines. In this section of the narrative, the Large Electrical Corporation must provide:*

   i. *A description of how the Project-Level Standard is evaluated in a manner which includes the effects of both Undergrounding Subprojects and non-undergrounding Subprojects.*

   ii. *A description of how Portfolio-Level metrics disaggregate the effects of non-undergrounding Subprojects for the measurement of the Plan Tracking Objectives and the Plan Mitigation Objective.*

   iii. *A description of how System-Level metrics disaggregate the effects of non-undergrounding Subprojects and any system hardening work on non-Portfolio Circuits for the measurement of the Plan Tracking Objectives and the Plan Mitigation Objective.*

h. *Explanatory graphs and figures.*

i. *Specific citations to any other EUP content that supports the Plan Mitigation Objective.*

j. A Target/Timeline Table with the following information about the timelines for completion, unit cost targets, mileage targets, anticipated start and end dates, risk reduction, and cost targets for each year of the EUP. Ignition Risk and Outage

Program Risk must be reported as described in Section 2.8.5.1. The information must be in table format in the EUP narrative and included as an Excel workbook.

i. Year of EUP;

ii. Dates for year of EUP;

iii. Underground mileage completion targets (per year and cumulative);

iv. Miles of overhead line deenergized;

v. Miles of Undergrounding in the Project Planning and Construction Phases;

vi. Unit cost targets for each year covered by the EUP;

vii. Risk reduction in instantaneous Ignition Risk for risk at year 10;

viii. Cumulative Ignition Risk reduction anticipated at the end of the expected lifetime (defined as 55 years) of the infrastructure;

ix. Increase in instantaneous Outage Program Risk reliability for risk at year 10; and

x. Cumulative Outage Program Risk reduction anticipated at the at the end of the expected lifetime (defined as 55 years) of the infrastructure.

1. PG&E's Plan Mitigation Objective Addresses All Energy Safety Requirements

Below PG&E explains that its Plan Mitigation Objective meets the requirements of Section 2.3.1 of the EUP Guidelines.

a. The Basis of the Plan Mitigation Objective (EUP Guidelines, Section 2.3.1(a))

The Plan Mitigation Objective represents the total quantified reduction in Ignition Risk and Outage Program Risk achieved through the implementation of the EUP. PG&E's Plan Mitigation Objective is measured using the monetized Overall Utility Risk reduction per primary overhead mile removed, providing an outcome-based metric that directly links EUP execution to Ignition and Outage Program risk reduction. The metric demonstrates that PG&E will deliver substantial, measurable reduction in Ignition Risk and Outage Program Risk through its execution of the EUP. The Plan Mitigation Objective ultimately provides a transparent, data-driven basis for evaluating the EUP's impact and

shows that the program materially advances statewide wildfire mitigation and reliability goals.

PG&E's implementation of the EUP is expected to reduce an average of $145,000 of Overall Utility Risk per mile of overhead conductor removed per year, based on unscaled risk values over PG&E's 10-year EUP period. This is equivalent to approximately $3 million in present-value Overall Utility Risk reduction per primary overhead mile removed over the 55-year life of the undergrounding assets.

PG&E's Plan Mitigation Objective was calculated using the Wildfire Distribution Risk Model (WDRM) v4 and the Outage Program Risk Model and was based on removal of approximately 4,000 miles of primary overhead lines (equivalent to approximately 5,000 miles of undergrounding), assuming the applicable entire Circuit Segments are relocated underground.

PG&E established the Plan Mitigation Objective using the approximately 4,000 overhead miles identified through the Project Acceptance Framework because those miles represent the forecast set of highest-risk Circuit Segments expected to be completed during the ten-year EUP period. The forecast Portfolio reflects a balanced consideration of risk reduction, affordability for customers, the pace at which projects can advance in coordination with communities, workforce availability, and constructability constraints.

PG&E expresses the Plan Mitigation Objective as a per-mile risk reduction target rather than a fixed Portfolio-level risk reduction value because it normalizes risk reduction across projects of varying size and complexity, providing a consistent and transparent measure of performance. The per-mile approach also allows the Plan Mitigation Objective to remain applicable and comparable over time as Portfolio composition evolves throughout the ten-year EUP period. Under this approach, the Plan Mitigation Objective is calculated by dividing the total projected Overall Utility Risk reduction associated with the forecast EUP Portfolio by the corresponding overhead miles removed, resulting in a

target of $145,000 of Overall Utility Risk reduction per overhead mile removed per year.

1) Plan Mitigation Objective Assumptions

The Plan Mitigation Objective applies climate-related risk escalation and inflation adjustments to the underlying risk values[66] to reflect the year in which the mitigation work is planned to occur. For example, if a project is scheduled to be undergrounded in 2031, the associated Wildfire and Outage Program Risk values are adjusted from their 2028 baseline to 2031 levels by accounting for projected climate change impacts and inflation.

The Plan Mitigation Objective only includes Circuit Segments that meet at least one of the Project Level Thresholds (i.e., high-risk eligible Circuit Segments) and are therefore eligible for consideration as high-risk projects. This includes, where applicable, Circuit Segments in Fire Rebuild Areas. For Fire Rebuild Projects, only risk reduction associated with Pre-Wildfire distribution infrastructure contributes to the Plan Mitigation Objective.[67] Circuit Segments entirely outside HFTD/HFRA are excluded from the Plan Mitigation Objective.

PG&E excludes Circuit Segments less than one mile long in the HFTD because the normalized costs and risk reduction metrics for such segments do not support meaningful per-mile comparisons and undergrounding them in isolation may present feasibility challenges.

PG&E apportions monetized Ignition Risk to each Circuit Segment based on its relative share of risk as represented by its WDRM v4 risk score. Future updates to the WDRM may alter the distribution of risk across the system, while updates to Enterprise

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66 These values are consistent with the climate and escalation assumptions used in the Wildfire Benefit Cost Analysis (WBCA). See Chapter 7, Section G.4 (Core Capability 4) for details of the assumptions.

67 The risk profile for the pre-wildfire distribution infrastructure for Fire Rebuild Projects where the fire occurred before January 1, 2023 would not be available for baseline comparisons. See discussion of previously-scoped projects in Chapter 3, Section D.5.

Bow Tie Model may alter the total quantity and monetized value of risk on PG&E's system.[68]

Because the Plan Mitigation Objective must remain fixed for the duration of the 10-year EUP despite ongoing model evolution as new data, methodologies, and regulatory requirements emerge, PG&E must account for the inherent variability, uncertainty, and model shifts that will occur over the life of the program.

Accordingly, PG&E expresses the Plan Mitigation Objective as a per-mile risk reduction target and incorporates a Risk Model Impact Factor of 20 percent into the calculation.[69]

The Risk Model Impact Factor reflects uncertainty arising from future changes between Ignition and Outage risk model versions. The Risk Model Impact Factor is comprised of two elements:

- **Risk Model Change Factor for Ignition Risk**: an estimated factor of 20 percent, representing the observed variance in Ignition Risk between WDRM v3 (previous version of the Wildfire Risk model) and WDRM v4 (current version of the Wildfire Risk model).
- **Risk Model Change Factor for Outage Risk**: an estimated factor of 18 percent which represents the observed variance in outage risk between the Interruption Cost Estimate (ICE) 1.0 and ICE 2.0 value of service.

As described in the subsections below, PG&E combined these two change factors to derive a consolidated Risk Model Impact Factor, rounded to 20 percent, to represent the expected uncertainty between current and future risk model versions. PG&E applies this factor as a 20 percent reduction to the projected Ignition and Outage Risk reductions calculated using the risk models available at the time of filing. This adjustment factor ensures the Plan Mitigation Objective remains applicable following future model revisions and

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68 PG&E will update the WDRM and reliability risk models based on the schedule outlined in Chapter 8, Section C.

69 PG&E developed the Risk Model Impact Factor methodology to quantify the uncertainty associated with future risk model changes.

continues to reflect a durable and transparent measure of risk reduction.

The adjusted risk reduction values for each EUP Circuit Segment are then aggregated and normalized by the associated mileage to calculate the Plan Mitigation Objective.

2) Risk Model Change Factor for Ignition Risk

PG&E's Risk Model Change Factor for Ignition Risk is derived by first calculating the Portfolio-Level Ignition Risk per mile,[70] also known as risk density, once using WDRM v3 and a second time using WDRM v4, to calculate the variance between the two results. The following outlines the calculation steps, detailing both the standard formula and the specific data used to calculate the variance that is then incorporated into the overall Risk Model Change Factor in our Plan Mitigation Objective.

1) **WDRM v3:** A WDRM v3 risk per mile value is calculated by dividing the percentage of Portfolio-Level WDRM v3 risk by the corresponding HFTD/High Fire Risk Area (HFRA) overhead primary miles. The starting population consists of 11,713 miles of overhead primary line associated with Circuit Segments containing one or more Confirmed Projects. To ensure a like-for-like comparison between WDRM v3 and WDRM v4, PG&E excludes approximately 683 miles where Circuit Segments cannot be reliably mapped between model versions, resulting in 11,029 comparable miles used in both calculations.[71] Using the same mileage denominator under each model ensures that the calculated variance reflects changes in risk model outputs rather than changes in the underlying asset population.

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70 Portfolio-Level refers to all Circuit Segments on each Circuit which has one or more Confirmed Projects.

71 Circuit Segment names and configurations may change. Even if a Circuit Segment's name exists in a subsequent version, actual segmentation and geometry may differ substantially, impacting comparability.

Formula: $\frac{\%\ of\ WDRM\ v.3\ risk\ at\ Portfolio-Level}{\#\ of\ \frac{HFTD}{HFRA}\ primary\ OH\ miles\ at\ Portfolio-Level} = \%\ per\ mile$

PG&E EUP: $\frac{67\%\ of\ WDRM\ v.3\ risk}{11{,}029\ miles} = 0.0061\%\ per\ mile$

2) **WDRM v4:** The same calculation using WDRM v4 risk to calculate risk per mile in the proposed EUP workplan.

Formula: $\frac{\%\ of\ WDRM\ v.4\ risk\ at\ Portfolio-Level}{\#\ of\ HFTD/HFRA\ primary\ OH\ miles\ at\ Portfolio-Level} = \%\ per\ mile$

PG&E EUP: $\frac{54\%\ \text{of WDRM v4 risk}}{11{,}029\ \text{miles}} = 0.0049\%\ \text{per mile}$

Note, PG&E's enterprise risk and wildfire distribution risk models include HFRA in their risk calculations because PG&E considers these areas to be high risk. However, as explained in Chapter 3, Section D.1.a, PG&E's EUP does not include underground Subprojects in HFRAs except the two adjacent spans allowed per the EUP Guidelines. (EUP Guidelines Section 2.4.3.1) Chapter 3, Section D.1. explains that PG&E may file a Petition for Modification to expand Tier 2 and Tier 3 HFTDs to include HFRA. If the HFTD maps are updated, PG&E may reassess Circuit Segment eligibility for the EUP.

3) Variance Between WDRM Models: Variance Is Assessed by Comparing WDRM v3 Risk Density Against WDRM v4 Risk Density.

Formula: $1 - \frac{WDRM\ v.4\ risk\ \%\ per\ mile}{WDRM\ v.3\ risk\ \%\ per\ mile} = risk\ \%\ variance$

PG&E EUP: $1 - \frac{0.0049\%}{0.0061\%} = 20\%\ risk\ variance^{*}$ $(0.005\%)/(0.006\%) = 20\%\ risk\ variance$

4) Risk Model Change Factor for Outage Risk

The Risk Model Change Factor for Outage Risk is derived from the ICE calculator based on the changes to the Value of Service (VoS) between ICE updates. The approach is noted below:

1) The VoS results from the two most recent ICE Calculator updates[72] are used to determine the Risk Model Change Factor for Outage Risk:

$$\textbf{Formula: } \frac{ICE\ 2.0\ VoS - ICE\ 1.0\ VoS}{Ice\ 1.0\ VoS} = \%\ variance$$

$$\textbf{PG\&E EUP: } \frac{\$2.72 - \$3.33}{\$3.33} = 18\%\ variance^{*}$$

**PG&E rounded to a 20% Risk Model Change Factor for simplicity.*

5) Risk Model Change Factor Calculation

Comparison of Ignition and Outage Risk calculations demonstrate material variability in risk density across model versions. PG&E used this variability between the previous and current versions of the WDRM risk models and ICE calculators to develop an estimate to account for future uncertainty. The Risk Model Change Factor for Wildfire Risk of 20 percent and the Risk Model Change Factor for Outage Risk of 18 percent are aggregated and rounded to a single Risk Model Impact Factor of 20 percent.

Tables 2-3 and 2-4 below summarize the calculation and Risk Model Change Factors for Wildfire and Outage Risk.

TABLE 2-3:
MODEL CHANGE FACTOR FOR IGNITION RISK CALCULATIONS

Line No.	Wildfire Risk Model Variance	WDRM v3	WDRM v4	Percent Change
1	HFRA(a)/HFTD Overhead Miles in Workplan	11,029	11,029	0
2	Percent of total WDRM Risk in Workplan	67%	54%	20%
3	Percent of total WDRM Risk per HFRA/HFTD Overhead Mile	0.006%	0.005%	20%

(a) See note above regarding reason HFRA is included.

72 See ICE Calculator v1 (pre-2025) and ICE Calculator v2 Documentation, available at: https://icecalculator.com/documents (accessed June 4, 2026).

TABLE 2-4:
MODEL CHANGE FACTOR FOR OUTAGE RISK CALCULATIONS

Line No.	ICE Calculator	Blended VoS
1	ICE 1.0 Blended (2024$)	$3.33
2	ICE 2.0 Blended (2024$)	$2.72
3	Percent of Outage Risk Change	18%

b. Risk and Reliability Scores Used to Set the Plan Mitigation Objective (EUP Guidelines, Section 2.3.1(b))

The Ignition Risk scores used to establish the Plan Mitigation Objective come from WDRM v4 and PG&E's Enterprise Risk Bow Tie Model.[73] The Enterprise Risk Bow Tie shows the risk exposure, risk scores, risk drivers, and modeled outcomes associated with the Wildfire Risk across PG&E's system. PG&E describes the Enterprise Bow Tie and the benefits and consequences of different mitigations in Chapter 7, Section D.7.

The Outage Risk scores used to establish the Plan Mitigation Objective are derived from PG&E's Outage Risk Model, with safety consequences adopted from PG&E's EPSS and PSPS risk bowties.

c. Minimum Levels of Ignition Risk and Outage Program Risk Reduction as Set Forth in the Portfolio-Level Standards (EUP Guidelines, Section 2.3.1(c))

PG&E describes our Portfolio-Level Standards, including the Portfolio-Level Ignition Risk Decrease Standard and the Portfolio-Level Reliability Increase Standard, in Chapter 7, Section L (related to the requirements of EUP Guidelines Section 2.7.8). Given that the Portfolio is the unique set of Confirmed Projects that have passed Screen 3 at any given time, PG&E's Portfolio metrics (that are measured against the Standards) will be updated in each Progress Report to reflect the minimum decrease in Ignition Risk and minimum increase in Outage Risk expected from the current Portfolio. The Portfolio Standards

[73] See Chapter 7, Section C and Section D for further detail on the WDRM and Enterprise Risk Bow Tie Model.

are included in our Portfolio Coversheet and Chapter 9 as Table PCS-2 and will be updated as the EUP progresses.

d. Overview of the EUP Implementation Approach and How the Approach Achieves the Plan Mitigation Objective (EUP Guidelines, Section 2.3.1(d))

PG&E's EUP implementation adheres to the Project Acceptance Framework of the EUP Guidelines, which is a four-screen, stepwise process that filters all Circuit Segments to identify, evaluate, and prioritize Undergrounding Projects that maximize Wildfire Risk reduction, reliability, and public safety while remaining cost-efficient. Circuit Segments progress from eligibility (Screen 1) to benefit-cost comparison (Screen 2), to detailed scoping and risk analysis (Screen 3), and finally to Portfolio-level prioritization and selection (Screen 4), with updates re-applied as conditions change.

In Screen 1, PG&E identifies eligible Circuit Segments (Tier 2 or 3 HFTD or Fire Rebuild Areas) and applies risk thresholds to determine which are eligible to proceed.

In Screen 2, PG&E first prioritizes Ignition Risk reduction by sorting Eligible Circuit Segments from Screen 1 in order from highest to lowest Wildfire Risk (i.e., from 1 through N or 1-N). We then evaluate these Eligible Circuit Segments using a BCR Alternative Mitigation Comparison. We use risk models and Alternative Mitigation analysis, namely the WDRM v4, Outage Program Risk Model and Wildfire Benefit Cost Analysis (WBCA) tool, to compare the potential Ignition Risk and Outage Risk of undergrounding to Alternative Mitigations.

In Screen 3, PG&E undertakes a more detailed assessment of the Undergrounding Projects by considering the mitigation comparison analysis from Screen 2, incorporating local risk factors at each Project location, and evaluating the appropriate mitigation approach within the Circuit Segment. This assessment allows PG&E to determine where undergrounding is appropriate within the Circuit Segment and where hybrid mitigations, including non-undergrounding mitigations, may be used to address localized risk and feasibility considerations while

ensuring undergrounding is targeted to the locations where it provides the greatest risk reduction and reliability benefit.

In Screen 4, PG&E sorts Confirmed Projects primarily by Overall Utility Risk per mile to consider both Ignition Risk and Outage Risk when prioritizing Undergrounding Projects.[74] (See Chapter 3 for further details about the screen process including details of the additional prioritization factors considered within the EUP Project Acceptance Framework.)

PG&E will use the Project Acceptance Framework described above to identify, evaluate, and prioritize Undergrounding Projects that are expected to deliver substantial Wildfire Risk reduction and reliability benefits and achieve our Plan Mitigation Objective. This approach is based on:

1) Identifying the highest Ignition and Outage Program Risk Circuit Segments in our service territory using WDRM v4 and the Outage Program Risk Model; and
2) Making data-driven decisions about where it is appropriate to deploy undergrounding, compared to other Alternative Mitigations, using WBCA outputs, Screen 3 local risk review, and Project-specific feasibility information.

This strategic targeting allows PG&E to focus undergrounding on the portions of Circuit Segments where it is expected to provide the greatest Overall Utility Risk reduction per mile, while using hybrid mitigation approaches where appropriate to address localized conditions. By applying this structured, data-driven process over the 10-year EUP period, PG&E will prioritize undergrounding that supports achievement of the Plan Mitigation Objective, substantially reduces Wildfire Risk, and significantly improves reliability.

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74 See Chapter 3, Section D.4 – Screen 4, Project Prioritization and Finalization, for further details of the Screen 4 prioritization approach.

e. Overview of How the Project Acceptance Framework, Project Timelines, Workforce Development, Non-ratepayer Funding, Progress Report 0, Risk Modeling, and Reporting Metrics Support the Plan Mitigation Objective (EUP Guidelines, Section 2.3.1(e))

PG&E's EUP incorporates numerous programmatic elements that support the successful achievement of PG&E's Plan Mitigation Objective and allow Energy Safety, the California Public Utilities Commission (CPUC or Commission), and stakeholders to monitor our progress towards achieving the Plan Mitigation Objective. Together, these elements guide project selection, support efficient program execution, quantify risk reduction, and provide transparent mechanisms for measuring performance against the Plan Mitigation Objective.

PG&E's Project Acceptance Framework supports the Plan Mitigation Objective by identifying, evaluating, and prioritizing Undergrounding Projects that provide the greatest reduction in Ignition Risk and Outage Program Risk. Through the four-screen evaluation process described in Chapter 3, PG&E focuses undergrounding investments on eligible high-risk Circuit Segments that are expected to deliver the most significant Overall Utility Risk reduction, thereby supporting achievement of the Plan Mitigation Objective.

Risk modeling provides the analytical foundation to the Plan Mitigation Objective. The Wildfire Distribution Risk Model, the Outage Program Risk Model, and the Enterprise Bow Tie Models are used to assess the risk associated with each EUP Project and evaluate the corresponding risk reduction benefits. These models are used not only to determine the Plan Mitigation Objective baseline but also support project selection decisions throughout the Project Acceptance Framework, and provide the basis for measuring progress toward achievement of the Plan Mitigation Objective over the ten-year EUP period. More information about PG&E's Risk Modeling can be found in Chapter 7.

Project completion timelines inform progress toward the annual, 5-year, and 10-year targets and objectives that culminate in achieving the Plan Mitigation Objective. These milestones provide a structured

roadmap for delivering undergrounding projects and achieving the forecast risk reductions that underpin the Plan Mitigation Objective. Detailed reporting metrics will be used to track our progress towards meeting our Plan Mitigation Objective, allowing us to identify and remedy any issues if we are off track. Metrics include the number of miles installed underground, the number of overhead miles deenergized, Overall Utility Risk reduction, Ignition and Outage Program Risk reduction, and instantaneous and cumulative risk reduction values.

Reporting metrics support the Plan Mitigation Objective by providing measurable indicators of performance. Metrics such as overhead miles de-energized, underground miles completed, Overall Utility Risk reduction, Ignition Risk reduction, Outage Program Risk reduction, and instantaneous and cumulative risk reduction values are used to evaluate whether the EUP is achieving the forecast outcomes. In particular, the Plan Tracking Objective metric “Risk Reduced per OH Mile De-Energized” will be used to demonstrate how PG&E is tracking toward the attainment of the Plan Mitigation Objective.

Workforce development supports the Plan Mitigation Objective by ensuring PG&E has the trained workforce necessary to safely and efficiently execute the forecast Portfolio of Undergrounding Projects. We are continuing to work with our workforce development programs to ensure we have the necessary workforce trained and available to deliver on our targets and timelines, and ultimately on our Plan Mitigation Objective. Further discussion is provided in EUP Chapter 5, Section C.2.

Non-ratepayer funding supports the Plan Mitigation Objective by reducing the cost to customers of achieving the forecast level of risk reduction. While non-ratepayer funding does not change the amount of risk reduction reflected in the Plan Mitigation Objective, it can reduce the customer-funded investment required to achieve that objective and improve the overall affordability of the EUP.

The information in Progress Report 0 and subsequent Progress Reports will give Energy Safety, the CPUC, and stakeholders transparent reporting of progress towards meeting our Plan Mitigation

Objective, including tabular and geospatial data related to our risk modeling methodology, Portfolio, and individual Undergrounding Projects. This report will be used to monitor our progress and identify any catch back or efficiency opportunities to remain on track to achieve our Plan Mitigation Objective by the end of year 10.

f. Summary of the Metrics and Standards for the Portfolio of Undergrounding Projects and Supporting Project-Level Metrics (EUP Guidelines, Section 2.3.1(f))

PG&E presents our EUP metrics in the EUP Target/Timeline Table in Section D.1.j, Table 2-12 and Plan Tracking Objectives in Section E, Table 2-13.

PG&E summarizes our standards and thresholds below in Table 2-5, and presents them in greater detail in the following locations:

- Plan Mitigation Objective: Chapter 2, Section D (above) (related to EUP Guidelines Section 2.3.1);
- Portfolio and System-Level Standards: Chapter 7, Section L (related to EUP Guidelines Section 2.7.8); and
- Project-Level Thresholds and Standards: Chapter 7, Sections M.1 and M.2 (related to EUP Guidelines Sections 2.7.9.1 and 2.7.9.2).

TABLE 2-5:
PORTFOLIO AND PROJECT STANDARDS AND THRESHOLDS

Line No.	Standard or Threshold	Value
1	High Risk Threshold	$0.029M OUR/OH Mile
2	Ignition Tail Risk Threshold	$52.437M per ignition
3	High Frequency Outage Program Threshold	5,559 outage minutes/year
4	High Risk Project-Level Standard	Varies
5	High Frequency Outage Program Project-Level Standard	90%
6	Tail Risk Project-Level Standard	90%
7	Ignition Portfolio-Level Standard – Portfolio Level	$0.045M /OH Mile
8	Outage Portfolio-Level Standard – Portfolio Level	$0.100M /OH Mile
9	Ignition Portfolio-Level Standard – System Level	$0.0023M /OH Mile
10	Outage Portfolio-Level Standard – System Level	$0.0049M /OH Mile

g. How Undergrounding Projects With Multiple Subprojects Will Be Reported and How the Risk Reduction Will Be Allocated Between Subprojects (EUP Guidelines, Section 2.3.1(g))

Undergrounding Projects with multiple Subprojects[75] will be reported in the Subproject Table (C.14) with each Progress Report. Table C.14 includes all Undergrounding Subprojects created from Projects that have passed Screen 4.

PG&E will allocate risk reduction among the Subprojects on a pro-rata basis per mile considering the mitigation effectiveness for each Alternative Mitigation and Additional Comparison.[76]

Below we address the three requirements in EUP Guidelines Section 2.3.1(g).

1) How the Project-Level Standard is Evaluated to Include the Effects of Both Undergrounding Subprojects and Non-Undergrounding Subprojects (EUP Guidelines Section 2.3.1(g)(i))

PG&E evaluates the Project-Level Standard by accounting for the cumulative effects of all mitigation measures applied across a Circuit Segment, including Subprojects with Non-EUP mitigations (e.g., Overhead Hardening and/or Remote Grid).

PG&E uses the term “Hybrid Project” to refer to a Project that includes undergrounding and non-undergrounding Subprojects on the same Circuit Segment. For Hybrid Projects, PG&E does not assess each mitigation in isolation. Instead, risk reduction is calculated by proportionally allocating pre-mitigation risk across the Circuit Segment based on the length treated by each mitigation type and then applying the applicable mitigation effectiveness to each portion. This approach ensures that the Project-Level Standard captures the combined performance of undergrounding and

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75 See EUP Guidelines, Appendix A, p. A-6. “‘Subproject’ means a delimited portion of work on a Confirmed Project. A Subproject must have a uniform set of mitigations applied to the entire Subproject. If a project does not have a uniform set of mitigations, it must be divided into more Subprojects.”

76 See Attach. B, WP012 (Core Capability 5: Supporting Formulas).

non-undergrounding Subprojects and reflects the total risk reduction achieved across the entire Circuit Segment.

Example: 10-Mile Hybrid Mitigation Project (hypothetical scenario with example values)

The example below illustrates the steps PG&E takes to assess each Project and Subproject against the required metrics, including the High-Risk Threshold and Project-Standard. The example includes six steps with hypothetical values and a discussion of the outcome. For Outage Program risks such as PSPS and EPSS, mitigation effectiveness is modeled as a reduction in event likelihood, while the consequences of such events remain unchanged. Risk reduction is therefore applied proportionally based on the extent a mitigation is applied to a Circuit Segment.

Example Step 1: Circuit Segment Configuration

- PG&E implements a 10-mile Hybrid Project on a Circuit Segment consisting of six miles of undergrounding and four miles of overhead hardening.
- Prior to mitigation, the Circuit Segment has $0.150 million of Ignition Risk and $0.300 million of Outage Risk.
- The pre-mitigated Overall Utility Risk per mile for this Circuit Segment would be ($0.150 million Ignition Risk + $0.300 million Outage Risk) / 10 miles = $0.045 million/mile.
- PG&E accounts for the effects of both mitigation types according to the simplified example below:

TABLE 2-6:
CIRCUIT SEGMENT CONFIGURATION VALUE

Line No.	Risk	Risk Value
1	Total Circuit Length	10 miles
2	Undergrounding Portion	6 miles
3	Overhead Hardening	4 miles
4	Mitigation Ratio	60% underground/40% overhead

Example Step 2: Pre-Mitigation Risk Assessment

For this hypothetical example, the entire project is evaluated for eligibility via the High-Risk Threshold. The pre-mitigated Overall Utility Risk per mile is $0.045 million/mile, exceeding the High-Risk Threshold[77] of $0.029 million/mile. This elevated risk profile qualifies the Project for further consideration in the EUP.

TABLE 2-7:
EXAMPLE STEP 2: PRE MITIGATION RISK ASSESSMENT (WHOLE NUMBERS)[78]

Line No.	Risk	Risk Value
1	Wildfire Risk	$0.150M
2	PSPS Risk	$0.130M
3	EPSS Risk	$0.170M
4	Total Risk	$0.450M
5	Pre-Mitigated OUR	$0.450M Total Risk/10 miles = $0.045/mile

Example Step 3: Risk Allocation by Mitigation Type

Risk allocation across the 10-mile Circuit Segment is proportionally distributed between the 6-mile undergrounding section and 4-mile overhead hardening section based on segment length ratios.

TABLE 2-8:
EXAMPLE STEP 3: RISK ALLOCATION BY MITIGATION TYPE

Line No.	Risk Type	Total Risk	Undergrounding	Overhead Hardening
1	Miles	10 miles	6 miles	4 miles
2	Wildfire Risk	$0.15M	$0.15M*(6/10) = $0.090M	$0.15M*(4/10) = $0.060M
3	PSPS Risk	$0.13M	$0.13M*(6/10) = $0.078M	$0.13M*(4/10) = $0.052M
4	EPSS Risk	$0.17M	$0.17M*(6/10) = $0.102M	$0.17M*(4/10) = $0.068M

77 High-Risk Threshold is defined as the Overall Utility Risk level above which a Circuit Segment is considered eligible for examination for expedited undergrounding. See Chapter 7, Section M 1 for further details.

78 The values in this example are hypothetical only.

Example Step 4: Mitigation Effectiveness Application

In this example undergrounding is assumed to be 92 percent effective in reducing Wildfire Risk. For PSPS and EPSS, mitigation effectiveness is modeled as a reduction in the event likelihood, with the consequence of such events remaining unchanged. Within the risk modeling framework, undergrounding is assumed to eliminate the likelihood of PSPS. For the purposes of forecasting, PG&E assumes that undergrounding eliminates PSPS and EPSS events on the underground portions of a Circuit Segment, resulting in 100 percent effectiveness for those risk categories. For Circuit Segments that are only partially undergrounded, PSPS and EPSS risk reduction is applied proportionally based on the extent of undergrounding.

Overhead Hardening demonstrates 45 percent Wildfire Risk reduction in this example. Overhead Hardening provides no PSPS risk reduction as PSPS events continue to be necessary to avoid Ignition Risk. Mitigation effectiveness for EPSS risk is assumed to be 52 percent for Overhead System Hardening. See Attach. B, WP001 (Mitigation Effectiveness Analysis) for detailed mitigation effectiveness values and assumptions.

Table 2-9 below shows how the mitigation effectiveness values are applied by mitigation type on a Hybrid Project:

TABLE 2-9:
EXAMPLE STEP 4: MITIGATION EFFECTIVENESS APPLICATION

Line No.	Mitigation Type	Wildfire Reduction	PSPS Reduction	EPSS Reduction	Total Reduction
1	Undergrounding ($0.270M of OUR)	$0.090M * 92% = $0.083M	$0.078M*100 % = $0.078M	$0.102M*100% = $0.102M	$0.263M
2	Overhead Hardening ($0.180M of OUR)	$0.060M × 45% = $0.027M	$0.052M × 0% = $0.000M	$0.068M × 52% = $0.035M	$0.062M
3	Combined Project	$0.110M	$0.078M	$0.137M	$0.325M

Example Step 5: Project-Level Standard Assessment

For this example, as seen in Table 2-10 below, the Hybrid Project achieves a risk reduction of approximately 72 percent. This is calculated by dividing the total risk reduction ($0.325 million) by the pre-mitigation risk exposure ($0.450 million). The Project-Level Standard for this Project is $0.016 million/mile (calculated as the difference between the pre-mitigated risk of $0.045 million/mile and High-Risk Threshold value of $0.029 million/mile), and therefore the risk reduction from the proposed mitigation exceeds the Project-Level Standard.

TABLE 2-10:
EXAMPLE STEP 5: PROJECT LEVEL STANDARD ASSESSMENT

Line No.	Assessment Metric	Value
1	Total Risk Reduction	$0.325M
2	Pre-Mitigation Risk Exposure	$0.450M
3	Residual Risk	$0.125M
4	Risk Reduction Percentage	72%
5	Pre-Mitigation Risk per Mile	$0.045M/mile
6	Post-Mitigation Residual Risk per Mile	$0.012M/mile
7	Risk Reduction per Mile	$0.033M/mile
8	Project-Level Threshold	$0.029M/mile

Example Step 6: High-Risk Threshold Compliance Verification

The 10-Mile Hybrid Project meets the regulatory requirements for High-Risk circuit mitigation. Both qualification criteria are satisfied: pre-mitigation risk exceeds the previously established High-Risk Threshold and post-mitigation residual risk falls below the High-Risk Threshold as indicated in Table 2-11 below.

TABLE 2-11:
EXAMPLE STEP 6: HIGH RISK THRESHOLD COMPLIANCE VERIFICATION

Line No.	Compliance Criterion	Value	**High-Risk Threshold**	Status
1	Pre-Mitigation Risk per Mile	$0.045M/mile	$0.029M/mile	Exceeds (Qualified)
2	Post-Mitigation Residual Risk per Mile	$0.012M/mile	$0.029M/mile	Below (Compliant)
3	Project Qualification Status	High-Risk Circuit	N/A	Confirmed

Example Outcome

The hybrid approach in this example (undergrounding and overhead hardening) has a pre-mitigated risk per mile of $0.045 million/mile, which exceeds the High-Risk Threshold of $0.029 million/mile, and a residual risk per mile of $0.012 million/mile which is below the High-Risk Threshold, satisfying the Project-Level Standard for High-Risk Circuit Segments.

2) Measurement of the Plan Tracking Objectives and Plan Mitigation Objective for Subprojects (EUP Guidelines Section 2.3.1(g)(ii) and (iii))

Only Undergrounding Projects or Undergrounding Subprojects count towards the Plan Tracking Objectives used to assess how the Portfolio develops over time and whether it is on track to meet the Plan Mitigation Objective explained in Section E below. PG&E will apply a pro-rata allocation of Circuit Segment risk to the Undergrounding Subprojects to determine the value of the Portfolio-level metrics associated with them.

When measuring the Plan Tracking Objectives and the Plan Mitigation Objective, PG&E isolates the performance of the EUP Portfolio by excluding risk reduction associated with non-EUP system hardening work (e.g., overhead hardening, Rule 20 projects funded in the GRC, or other non-EUP mitigations). This ensures that system-level metrics reflect progress toward the EUP's undergrounding-specific objectives and do not double-count risk reduction achieved through other programs.

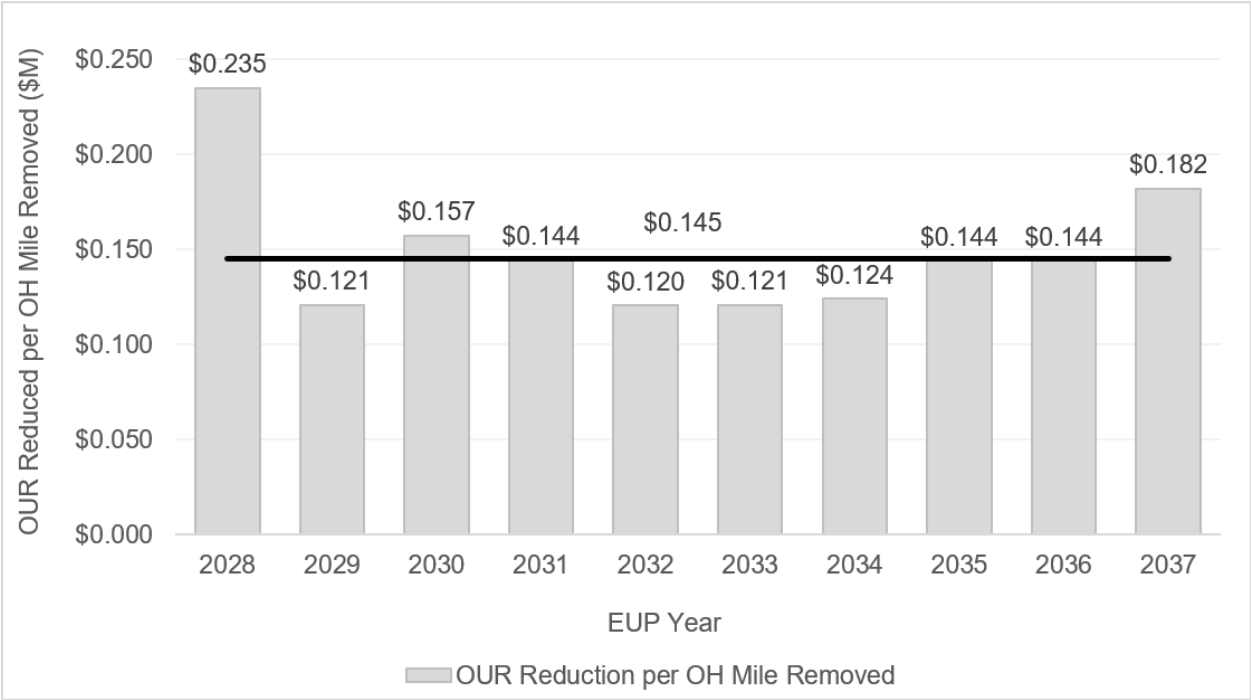
Similar to the Portfolio level approach described above, for Circuit Segments where non-EUP system hardening work is present, PG&E applies a pro-rata allocation of Circuit Segment risk based on the length and scope of the non-EUP work to quantify the portion of risk reduction attributable to those activities. That allocated risk reduction is then explicitly excluded from the system-level metrics used to track progress against the Plan Tracking Objectives and the Plan Mitigation Objective.

As a result, system-level metrics measure only the incremental risk reduction associated with EUP Undergrounding Projects, while the effects of other system hardening work on non-Portfolio Circuit Segments are identified and reported in the Non-EUP Project Table (Attach. A, Table C.22). Non-EUP Project metrics are excluded from the EUP metrics.

h. Explanatory Graphs and Figures (EUP Guidelines, Section 2.3.1(h))

Figure 2-1 below presents the estimated annual contribution toward achievement of the Plan Mitigation Objective over the 10-year EUP period, expressed as Overall Utility Risk (OUR) reduction per overhead mile removed for projects forecasted to be completed in each year. Annual values vary based on the characteristics of the forecasted project Portfolio, including underlying wildfire and reliability risk, climate-related risk escalation, inflation adjustments, and Portfolio composition. Because individual projects are selected and scheduled based on risk, cost, feasibility, and constructability considerations, the annual risk reduction per mile is expected to vary over time. Although the Plan Mitigation Objective is evaluated across the full 10-year EUP Portfolio, Figure 2-1 provides transparency into the projected timing and annual distribution of risk reduction expected to contribute to achievement of the Plan Mitigation Objective.

FIGURE 2-1:
PLAN MITIGATION OBJECTIVE ANNUAL VIEW



i. Other EUP Content that Supports the Plan Mitigation Objective (EUP Guidelines, Section 2.3.1(i))

The Plan Mitigation Objective is the summation of PG&E's EUP and represents PG&E's fundamental objective: to significantly reduce Ignition and Outage Program Risk in the HFTD through undergrounding. Therefore, all the content in EUP Chapters 3 through 9, in Attach. A (Progress Report 0 and the Portfolio Coversheet) and Attach. B workpapers support the Plan Mitigation Objective. Key content includes:

- Target/Timeline Table: Chapter 2, Section D.1.j (EUP Guidelines Section 2.3.1);
- Project Acceptance Framework: Chapter 3, Section C (EUP Guidelines Section 2.4) and Section D (EUP Guidelines Sections 2.4.3 through 2.4.6);
- Circuit Segment Information Lists: Chapter 4, Section C (EUP Guidelines Section 2.4.7);
- Costs and Benefits: Chapter 5, Section C.3 (EUP Guidelines Section 2.5.3);

- Progress Report 0: Chapter 6, Section C (EUP Guidelines Section 2.6);
- Overview of Risk Modeling Methodology: Chapter 7, Section C.1 (EUP Guidelines Section 2.7.1);
- Model Reports: Chapter 7, Section D (EUP Guidelines Section 2.7.2);
- Key Decision-Making Metrics: Chapter 7, Section E (EUP Guidelines Section 2.7.3);
- Enterprise Diagrams: Chapter 7, Section E.1 (EUP Guidelines Section 2.7.3.1);
- Required Core Capabilities for Risk Modeling Methodology: Chapter 7, Section G (EUP Guidelines Section 2.7.5);
- Portfolio and System-Level Standards: Chapter 7, Section L (EUP Guidelines Section 2.7.8);
- Project-Level Thresholds: Chapter 7, Section M.1 (EUP Guidelines Section 2.7.9.1);
- Project-Level Standards: Chapter 7, Section M.2 (EUP Guidelines Section 2.7.9.2);
- Model Retention and Update Schedule: Chapter 8, Section C (EUP Guidelines Section 2.7.6);
- Reporting Metrics: Chapter 9, Section C (EUP Guidelines Section 2.8);
- Portfolio Coversheet Overview: Chapter 9, Section E (EUP Guidelines Section 2.8.6.1);
- System and Portfolio-Level Risk Matrices and Profiles for Key Decision-Making Metrics: Chapter 9, Section F (EUP Guidelines Section 2.8.6.2); and
- Portfolio Development: Chapter 9, Section G (EUP Guidelines Section 2.8.6.3).

j. A Target/Timeline Table with Information about the Timelines for Completion, Unit Cost Targets, Mileage Targets, Anticipated Start and End Dates, Risk Reduction, and Cost Targets for Each Year of the EUP (EUP Guidelines, Section 2.3.1(j))

Table 2-12 below is PG&E's Target/Timeline Table. It is also provided in Progress Report 0 as Attach. A, Table A-2, and as required in EUP Guidelines Section 2.3.1(j), PG&E includes an excel workbook as Attach. B, WP002 (EUP Target/Timeline Table).

TABLE 2-12:
TARGET/TIMELINE TABLE

Line No.	Year	Date Range	Miles Completed[a]	OH Miles De-energized	Cumulative Miles Completed[a]	Preconstruction Miles[b]	Unit Cost Target (Escalated)[c]	Unit Cost Target (Unescalated)[c]	Change in Instant Wildfire Risk Year 10[d][e]	Change in Cumulative Wildfire Risk Over 55 Years[d][e]	Change in Instant Reliability Risk Year 10[d][e]	Change in Cumulative Reliability Risk Over 55 Years[d][e]
	Units:	Date Range	Miles	Miles	Miles	Miles	Millions of Dollars/Mile	Millions of Dollars/Mile	Millions of Dollars	Millions of Dollars	Millions of Dollars	Millions of Dollars
1	1	1/1/2028 - 12/31/2028	250	200	250	650	$3.05	$3.05	~~$18~~ $22	~~$1,085~~ $2,221	~~$42~~ $51	~~$2,959~~ $6,289
2	2	1/1/2029 - 12/31/2029	300	240	550	800	3.10	3.03	~~23~~ 28	~~1,338~~ 2,749	~~14~~ 17	~~859~~ 1,796
3	3	1/1/2030 - 12/31/2030	350	280	900	1,000	3.14	3.00	~~21~~ 25	~~1,200~~ 2,484	~~31~~ 37	~~1,945~~ 4,106
4	4	1/1/2031 - 12/31/2031	450	360	1,350	1,150	3.18	2.98	~~24~~ 29	~~1,348~~ 2,816	~~42~~ 51	~~2,524~~ 5,335
5	5	1/1/2032 - 12/31/2032	550	440	1,900	1,225	3.23	2.96	~~24~~ 30	~~1,351~~ 2,846	~~39~~ 48	~~2,967~~ 6,613
6	6	1/1/2033 - 12/31/2033	600	480	2,500	1,250	3.30	2.95	~~24~~ 30	~~1,370~~ 2,920	~~44~~ 54	~~3,253~~ 7,274
7	7	1/1/2034 - 12/31/2034	625	500	3,125	1,250	3.36	2.94	~~23~~ 28	~~1,277~~ 2,759	~~48~~ 58	~~3,222~~ 7,185
8	8	1/1/2035 - 12/31/2035	625	500	3,750	1,250	3.42	2.92	~~20~~ 25	~~1,070~~ 2,314	~~55~~ 67	~~3,236~~ 7,125
9	9	1/1/2036 - 12/31/2036	625	500	4,375	625	3.49	2.91	~~17~~ 21	~~927~~ 2,031	~~61~~ 75	~~4,110~~ 9,319
10	10	1/1/2037 - 12/31/2037	625	500	5,000	0	3.56	2.90	~~16~~ 19	~~803~~ 1,769	~~78~~ 95	~~5,877~~ 13,629
11	End Total	12/31/2037	5,000	4,000	5,000	0			~~$208~~ $255	~~$11,768~~ $24,908	~~$453~~ $554	~~$30,953~~ $68,670

(a) Underground mileage is estimated by applying a 1.25 multiplier to the corresponding overhead mileage deenergized. The 2028 undergrounding mileage shown in the EUP Target/Timeline Table (250 miles) differs from the mileage approved in the 2026 WMP (400 miles). The difference is primarily due to the time needed to transition the program and its supporting structure to meet the EUP requirements. Once the EUP is approved, PG&E will update the WMP mileage at the appropriate time.

(b) Pre-construction miles are calculated as the sum of undergrounding miles required to be in the planning process in the next two years that are needed to meet execution targets. These miles reflect the number of miles passing Screens 3 and 4. There is a two year-lead time for pre-construction miles (e.g., 650 miles in 2028 is the sum of planned miles for 2029 and 2030).

(c) To establish 2028 unit cost values, 2025 actuals are escalated to 2028 dollars. The "Unit Cost Escalated" column reflects annual unit cost values further escalated from 2028 dollars to the dollar value in the applicable year (2028–2037). The "Unit Cost Unescalated" column reflects annual unit cost values presented in unescalated 2028 dollars and incorporates assumed unit cost reductions over time as program efficiencies are realized. Cost assumptions applied in the current WBCA model for Screen 2 are based on average 2028 unit costs; however, costs for individual projects may vary based on project-specific feasibility multipliers.

~~(d) Instantaneous and cumulative risk values represent unmitigated Wildfire and Outage Program Risk for all years prior to Project completion, and post-mitigated risk from the year the Project is completed onward. PG&E applies the Risk Model Impact Factor, climate escalation, and inflation adjustments as described in this section.~~

(d) Change in Instantaneous Wildfire Risk at Year 10 and Change in Instantaneous Outage Program Risk at Year 10 represents the difference between the circuit segment's projected unmitigated risk and post-mitigation residual risk in 2037. Both values reflect applicable inflation and climate escalation adjustments. Change in Cumulative Wildfire Risk Over 55 Years and Change in Cumulative Outage Program Risk Over 55 Years represent the cumulative difference between the circuit segment's projected unmitigated risk and post-mitigation residual risk over the 55-year evaluation period. Both values reflect applicable inflation and climate escalation adjustments throughout the evaluation period.

(e) Totals may not exactly equal the sum of individual values because figures are rounded independently.

PG&E will provide an updated Target/Timeline Table in subsequent Progress Reports which will include actual values for completed years of the EUP and forecast values for the remaining years. PG&E will compare each updated table to the most recent table rather than to the original Baseline.

For example, in Progress Report 13 (submitted in 2033 assuming a 2028 EUP start date) PG&E will report actual values for 2028 through 2032 and forecast values for 2033 through 2037. PG&E will compare the forecast values reported in Progress Report 13 to the recorded values reported in Progress Report 12 (not to the plan tracking values reported in Progress Report 0).

When PG&E updates risk models, we will update the forecast risk values in the Target/Timeline Table provided in the following Progress Report and will backtest those values so that they are comparable to the values provided in Progress Report 0 that were created based on the WBCA. We do not expect the backtested values to align to the original assumptions for multiple reasons, including changes in circuit geometries, other system hardening and mitigations that are applied, and operational updates to Circuit Segments. Therefore, mitigated lines will show reduced or no risk.

In each Progress Report, we will review our progress against the forecast values and will provide a variance explanation for any actual value that varies from the forecast amount. PG&E will also update the values in the Target/Timeline Table to more closely align them to the current EUP and Progress Report. For example, if the number of overhead miles deenergized in 2033 is less than the forecast number, we would explain the variance. We may also increase the forecast number of overhead miles deenergized in future years to make up for any shortfall in 2033 if needed to achieve the 10-year Plan Mitigation Objective.

E. Plan Tracking Objectives (EUP Guidelines, Section 2.3.2)

To track and evaluate progress toward the Plan Mitigation Objective, the EUP must also include specific Plan Tracking Objectives. The Plan Tracking Objectives will be used to assess how the Portfolio of projects develops over time and whether the Large Electrical Corporation is on track to meet the Plan Mitigation Objective. The Plan Tracking Objectives must consist of forward-looking, quantifiable measurements and objectives, measured at the Portfolio-Level and System-Level, that will be used to assess progress toward the Plan Mitigation Objective. The list of Plan Tracking Objectives must:

a. Be specific, measurable, achievable, realistic, and timely outcomes for the EUP.

b. Include annual and 5-year tracking objectives.

c. Include tracking objectives based on total Overall Utility Risk Reduction.

d. Include some tracking objectives based solely on Ignition Risk Reduction and some based solely on Outage Program Risk.

e. Include tracking objectives measured by risk reduced per mile.

f. Include tracking objectives measured in miles of overhead line deenergized.

g. Include tracking objectives measured in number of projects that have completed Screens 3 and 4.

The Independent Monitor will use the Plan Tracking Objectives, and other EUP objectives to assess the Large Electrical Corporation's progress with implementation of its EUP. The Plan Tracking Objectives will be tracked in all Progress Reports pursuant to sections 8388.5(f)(3) and 8388.5(g).

The Plan Tracking Objectives are the Large Electrical Corporation's current forecast plan for meeting the Plan Mitigation Objective. Each Progress Report must use performance metrics to compare and update the Plan Tracking Objectives. The Progress Report must explain the reasons for any changes to the Plan Tracking Objectives.

The EUP must contain a narrative setting forth the process the Large Electrical Corporation will use to compare and update Plan Tracking Objectives in each Progress Report.

Plan Tracking Objectives will be used to assess how the Portfolio develops over time and whether PG&E is on track to meet the Plan Mitigation Objective. Plan Tracking Objectives will also be used by the Independent Monitor to assess PG&E's compliance with our approved plan and will be included in all Progress Reports pursuant to Public Utilities Code Sections 8388.5(f)(3) and 8388.5(g).

1. List of Plan Tracking Objectives

Table 2-13 below shows PG&E's proposed specific, measurable, achievable, realistic and timely Plan Tracking Objectives for the EUP, which include:

- Annual and 5-year objectives (year-5 and year-10);
- Tracking objectives based on Overall Utility Risk reduction, Ignition Risk reduction and Outage Program Risk reduction;
- Plan Tracking Objectives measured by risk reduced per mile installed and by miles of overhead line deenergized; and
- Plan Tracking Objectives measuring the number of Projects completed in Screen 3 and Screen 4.

TABLE 2-13:
PG&E'S PLAN TRACKING OBJECTIVES
(MILLIONS OF DOLLARS)

Line No.	PTO[a] Year	OH Miles Deenergized	C Total OUR Reduction Target[b] [c]	D.1 Ignition Risk Reduction Target[b]	D.2 Outage Program Risk Reduction Target[b]	E Risk Reduced Per Mile Installed[b]	F Risk Reduced per OH Mile Deenergized [b]	G Count of Projects that have Completed S3 + S4
1	2028	200	$47	$14	$34	$0.190	$0.239	93
2	2029	240	29	18	11	0.096	0.120	134
3	2030	280	44	18	26	0.125	0.156	169
4	2031	360	52	19	33	0.117	0.146	202
5	2032	440	53	21	32	0.096	0.121	232
6	**2028-2032 5 Year Goal**	**1,520**	**$225**	**$90**	**$135**	**$0.119**	**$0.148**	**232**
7	2033	480	$58	$22	$37	$0.097	$0.122	277
8	2034	500	62	20	42	0.100	0.124	321
9	2035	500	72	19	53	0.115	0.144	360
10	2036	500	72	16	55	0.115	0.143	360
11	2037	500	91	15	76	0.146	0.182	360
12	**2033-2037 5 Year Goal**	**2,480**	**$355**	**$92**	**$263**	**$0.115**	**$0.143**	**360**
13	**Total**	**4,000**	**$581**	**$183**	**$398**	**$0.116**	**$0.145**	**360**

Note: PG&E applies the same Risk Model Impact Factor, climate escalation and inflation adjustments to the Plan Tracking Objectives as we do to the Plan Mitigation Objective. This is described in the EUP Guidelines, Section 2.3.1.

(a) The Plan Tracking Objective identifier aligns to the list of Plan Tracking Objectives in the EUP Guidelines, Section 2.3.2.

(b) Risk values represented in the Plan Tracking Objectives include the Risk Model Impact Factor reduction of 20 percent.

(c) OUR Reduction Target may not exactly equal the sum of individual values of Ignition and Outage Program Risk reduction targets because figures are rounded independently.

2. Process to Update the Plan Tracking Objectives in each Progress Report

PG&E's initial Plan Tracking Objectives are in Table 2-13 above. We will provide an updated Plan Tracking Objectives table in each Progress Report. The update will report actual values for completed years of the EUP and forecast values for the remaining years. Only EUP Projects count toward the Plan Tracking Objectives, which include Fire Rebuild Projects that have qualified for the EUP. Non-EUP Projects are excluded from the Plan Tracking Objectives. Core Capability 5 (described in Chapter 7, Section G.5.a) details the methodology for the allocation of risk and risk reduction to subprojects. Only the allocated risk reduction associated with the Undergrounding Subprojects of a Circuit Segment will count towards the Plan Mitigation Objective and Plan Tracking Objectives. Risk reduction associated with non-undergrounding Subprojects is separately quantified for Project-Level evaluations but excluded from Plan Mitigation Objective and Plan Tracking Objectives attainment calculations. PG&E will compare each updated Plan Tracking Objective table to the most recent table and not to the original Baseline, to allow for more meaningful variance explanations and align with the requirements of the EUP.[79] In each Progress Report, PG&E will provide an explanation for changes between planned and actual values, as needed.

When PG&E updates our risk models, we will update the Plan Tracking Objectives in the subsequent Progress Report and will backtest those values to make the metrics comparable to the Plan Tracking Objectives provided in Progress Report 0 that were based on the version of WBCA in effect when we filed the EUP.

In each Progress Report, PG&E will review our progress against the forecast Plan Tracking Objectives. We will also update our Plan Tracking Objectives to more closely align them to the current EUP and our progress towards achieving the 10-year objective.

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79 EUP Guidelines, p. 9, Section 2.3.2.

F. Risk Calculations for Non-Undergrounding Subprojects (EUP Guidelines, Section 2.3.3)

If the Undergrounding Project includes non-undergrounding Subprojects, the non undergrounding work is counted as follows:

a. ***Project Threshold*** *(see Sections 2.4.3.2 and 2.7.5): for purposes of determining if the Circuit Segment meets a Project Threshold, use the risk score for the entire Circuit Segment (including any potential non undergrounding Subprojects).*

b. ***Plan Mitigation Objective and Plan Tracking Objectives*** *(see Sections 2.3.1, 2.3.2 and 2.7.5): for purposes of determining progress towards and compliance with the Plan Mitigation Objective and Plan Tracking Objectives, only use the risk reduction attributed to the Undergrounding Subprojects.*

c. ***Comparative Metrics*** *(see Section 2.7.10): for purposes of comparative metrics, use the risk reduction for the entire Circuit Segment when determining whether the project meets the Project Level Standard, but only apply the risk reduction attributed to the Undergrounding Subprojects towards the Plan Mitigation Objective.*

PG&E describes how we account for non-EUP Subprojects included in an Undergrounding Project in the following locations:

- Project-Level Thresholds: Chapter 7, Section M.1 (EUP Guidelines Section 2.7.9.1);
- Plan Mitigation Objective and Plan Tracking Objectives: Chapter 2, Sections D and E (EUP Guidelines Sections 2.3.1 and 2.3.2, respectively); and
- Comparative Metrics: Chapter 7, Section N (EUP Guidelines Section 2.7.10).

G. Risk Calculations for Projects Extending Beyond a Confirmed Polygon (EUP Guidelines, Section 2.3.4)

If the scope of a project changes to include sections outside of the Confirmed Project Polygon (see Sections 2.4.2.4 and C.4.2), risk for the project is counted as follows:

a. ***Expansion outside of a Confirmed Project Polygon****: in the event that a portion of another Circuit Segment outside of the Confirmed Project Polygon is added to a project, use the risk reduction for the full (expanded) project for determining the contribution towards the Plan Mitigation Objective and use only the work inside the original Confirmed Project Polygon for determining whether the project meets the Project-Level Standard (see Section 2.7.9.2).*

If a portion of another Circuit Segment outside of the Confirmed Project Polygon is added to a Project, we will use the risk reduction for the full Project (including the portion that extends beyond the confirmed polygon) to determine the contribution towards the Plan Mitigation Objective. We will use only the work inside the original Confirmed Project Polygon to determine whether the Project meets the Project-Level Standard.

H. Risk Calculations for Projects in Fire Rebuild Areas (EUP Guidelines, Section 2.3.5)

If the Circuit Segment is in a Wildfire Rebuild Area (see Section 2.4.3.1), risk for the Circuit Segment is calculated as follows:

a. ***Project Threshold*** *(see Sections 2.4.3.2, 2.7.5 and Appendix C.1.10): The Pre-Wildfire distribution infrastructure and associated risk scores are used to determine if the Circuit Segment meets the Project Thresholds.*

b. ***Screen 3 Comparisons*** *(see Sections 2.4.5 and 2.7.10): for purposes of the Screen 3 Comparative Metrics, the Pre-Wildfire distribution infrastructure and associated risk must be used as the comparison Baseline.*

c. ***Plan Mitigation Objective and Plan Tracking Objectives*** *(see Sections 2.3.1, 2.3.2 and 2.7.5): the risk reduction from a Wildfire Rebuild Area Undergrounding Project is compared to Pre-Wildfire distribution infrastructure and associated risk scores for purposes of determining progress towards the Plan Mitigation Objective and Plan Tracking Objectives.*

PG&E describes how we account for risk if a Circuit Segment is in a Fire Rebuild Area in the following sections of the EUP:

- Project-Level Thresholds: Chapter 7, Section M.1;
- Screen 3 Project Risk Analysis: Chapter 3, Section D.3; and
- Plan Mitigation Objective and Plan Tracking Objectives: Chapter 2 Section D (Plan Mitigation Objective) and Section E (Plan Tracking Objectives) above.

I. Chapter Summary

This chapter explains how PG&E satisfies Section 2.3 of the EUP Guidelines by demonstrating substantial Wildfire Risk reduction and improved reliability. It describes the Plan Mitigation Objective, the risk framework used to measure progress and the targets and timelines for achieving results over the 10-year plan period.

The chapter also outlines the Plan Tracking Objectives and explains how PG&E will calculate and report risk reduction for undergrounding and related Project components, including non-undergrounding Subprojects, Projects extending beyond confirmed polygons, and Projects in Fire Rebuild Areas. Together, these sections provide the basis for tracking progress and demonstrating compliance with the EUP Guidelines.

J. Chapter 2 Supporting Attachments Index

The attachments/workpapers in Table 2-14 below support this chapter.

TABLE 2-14:
CHAPTER 2 SUPPORTING ATTACHMENTS/WORKPAPERS INDEX

Line No.	EUP Section	EUP Location	Workpaper/Table Name	File Name
1	2.D.1.c	Attachment A-1	Portfolio Coversheet Table PCS-2	PGE_AtchA1_2026-~~09~~10-30_Progress Report 0 Portfolio Cover Sheet_R0
2	2.D.1.g	Attachment B	WP001 (Mitigation Effectiveness Analysis)	PGE_WP001_2026-09-30_Mitigation Effectiveness Analysis_R0
3	2.D.1.g	Attachment B	WP012 (Core Capability 5: Supporting Formulas)	PGE_WP012_2026-09-30_Core Capability 5: Supporting Formulas_R0
4	2.D.1.g	Attachment A-2	Progress Report 0 – Table C.14 Subproject Table	PGE_Initial_2026-~~09-30~~10-12_T14_R0
5	2.D.1.j	Attachment B	WP002 (EUP Target / Timeline Table)	PGE_WP002_2026-~~09~~10-30_EUP Target Timeline Table_R0
6	2.E.2	Attachment A	Progress Report 0 Narrative	PGE_AtchA_2026-~~09~~10-30_Progress Report 0 Narrative_R0
7	2.D.1.g	Attachment A-2	Progress Report 0 – Table C.22 Non-EUP Projects	PGE_Initial_2026-09-30_T22_R0

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 3

PROJECT ACCEPTANCE FRAMEWORK

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 3
PROJECT ACCEPTANCE FRAMEWORK

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) addresses the requirements in Sections 2.4.1 to 2.4.6 of the Electrical Undergrounding Plan (EUP) Guidelines, including: (1) changes to Circuit Segment Information; (2) a description of the Project Acceptance Framework; and (3) a list of the highest Circuit Segment scores for various risks.

Section B lists the requirements from Senate Bill (SB) 884 and the EUP Guidelines addressed in this chapter.

Section C describes how PG&E applies and maintains the Project Acceptance Framework over time, including how Circuit Segments progress through the screens and how changes are incorporated after the EUP is submitted. These sections explain how PG&E accounts for updated risk information, Fire Rebuild areas, Project scoping details, Subprojects, and physical changes to Circuit Segments through reapplication of screens where necessary. We also address standardized tracking and reporting processes used to maintain the framework that is current, consistent, and traceable throughout the EUP period.

Section D describes the four screens that comprise the Project Acceptance Framework. The Project Acceptance Framework of Screens 1 through 4 illustrates the process to screen Projects from the entire High-Fire Threat District (HFTD) population to identify Confirmed Projects for the EUP Portfolio.[80] Section D also introduces our first Portfolio (Portfolio 0) and describes how Projects in Portfolio 0 were selected.

Section E provides a chapter summary and Section F lists supporting attachments.

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80 The 10-year Portfolio may reflect more than 5,000 miles as operational constraints may prevent some from being constructed within the EUP and we propose to execute the committed 5,000 miles over the EUP period.

B. Undergrounding Plan Requirements

In Tables 3-1 and 3-2 below, we identify each of the statutory and EUP Guidelines requirements that are addressed in this chapter.

TABLE 3-1:
SB 884 REQUIREMENTS ADDRESSED IN CHAPTER 3

Line No.	Public Utilities Code Section	Legislative Requirement	Where Requirement is Addressed
1	8388.5(c)(2)	Identification of the undergrounding projects that will be constructed as part of the program, including a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. Only undergrounding projects located in Tier 2 or Tier 3 HFTD or rebuild areas may be considered and constructed as part of the program.	Chapter 3 in totality
2	8388.5(c)(4)	A comparison of undergrounding versus above ground hardening of electrical infrastructure and wildfire mitigation for achieving comparable risk reduction or any other alternative mitigation strategy, such as covered conductor and rapid earth fault current limiter devices, for those prioritized undergrounding projects, evaluating the scope, cost, extent, and risk reduction of each activity, separately and collectively, over the duration of the plan. The comparison shall emphasize risk reduction and include an analysis of the cost of each activity for reducing wildfire risk, separately and collectively, over the duration of the plan.	Chapter 3 in totality

TABLE 3-2:
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS ADDRESSED IN CHAPTER 3

Line No.	EUP Guidelines Section	EUP Guidelines Requirements	Requirement Reference in Chapter 3
1	2.4	Project Acceptance Framework	Section C
2	2.4.1	Project Progression Through Screens	Section C.1
3	2.4.2	Incorporating Changes	Section C.2
4	2.4.2.1	Changes to Circuit Segment	Section C.2.a
5	2.4.2.2	Subprojects	Section C.2.b
6	2.4.2.3	Other Anticipated Changes	Section C.3
7	2.4.2.4	Physical Changes to a Circuit Segment	Section C.4
8	2.4.3	Screen 1: Circuit Segment Eligibility	Section D.1
9	2.4.3.1	Identification Of Circuit Segments Inside and Outside of a Tier 2 or 3 High Fire Threat Districts and Fire Rebuild Areas	Section D.1.a
10	2.4.3.2	Identification of Risky Circuit Segments and Mitigation Standards	Section D.1.b
11	2.4.4	Screen 2: Project Information and Alternative Mitigation Comparison	Section D.2
12	2.4.4.1	Common Set of Values and Assumptions	Section D.2.a
13	2.4.5	Screen 3: Project Risk Analysis	Section D.3
14	2.4.5.1	Screen 3 Procedure	Section D.3.a
15	2.4.5.2	Twenty-Five Undergrounding Project Requirement	Section D.3.b
16	2.4.6	Screen 4: Project Prioritization and Finalization	Section D.4

C. Project Acceptance Framework Requirements (EUP Guidelines Section 2.4)

Pursuant to section 8388.5(c)(2), the Large Electrical Corporation must identify Undergrounding Projects in its EUP. The Project Acceptance Framework is a multi-step process that the Large Electrical Corporation must establish and use to determine which Circuit Segments can be considered Undergrounding Projects, and, if undergrounded, will substantially increase electrical reliability and substantially reduce the risk of wildfire.

The Large Electrical Corporation must list all Circuit Segments in its service territory (the "All Circuit Segment List"), apply the Project Acceptance Framework to that list, and include the results in the EUP as described below. The Large Electrical Corporation must demonstrate that projects successfully passing through the Project Acceptance Framework contribute to achieving the Plan Mitigation Objective. The Project Acceptance Framework has four screens:

Screen 1: Circuit Segment Eligibility

Screen 2: Project Information and Alternative Mitigation Comparison

Screen 3: Project Risk Analysis

Screen 4: Project Prioritization and Finalization

In Section D below, we describe how we use our Project Acceptance Framework to determine which Circuit Segments can be considered Confirmed Projects that will substantially increase electrical reliability and reduce Wildfire Risk.

1. Project Progression Through Screens (EUP Guidelines Section 2.4.1)

The Project Acceptance Framework has a procedure for progressing a Circuit Segment through the four screens:

Screen 1 Procedure. *The EUP must apply Screen 1 (Circuit Segment Eligibility) to all Tier 2 or 3 High Fire Threat District (HFTD) and non-HFTD Circuit Segments and any Wildfire Rebuild Areas at the time of EUP filing. The Large Electrical Corporation must identify any Wildfire Rebuild Areas using the procedure described by the Large Electrical Corporation pursuant to Section 2.4.3.1 below. Circuit Segments that are not located in a Wildfire Rebuild Area or a Tier 2 or 3 HFTD ("Out of Area Circuit Segments") are eliminated in Screen 1. Each Circuit Segment that is located in a Wildfire Rebuild Area or a Tier 2 or 3 HFTD is then evaluated to determine if the Circuit Segment meets the risk score criteria for eligibility. In-Area Circuit Segments that meet the risk score criteria are "Eligible Circuit Segments" and proceed to Screen 2. In-Area Circuit Segments that do not meet the risk score criteria are "Ineligible Circuit Segments" and do not proceed to Screen 2.*

Screen 2 Procedure. *The EUP must apply Screen 2 (Project Information and Alternative Mitigation Comparison) to all Eligible Circuit Segments. Circuit Segments that pass Screen 2 are considered "Undergrounding Projects" and can proceed to Screen 3. These Undergrounding Projects constitute the list of Undergrounding Projects that must be identified in the EUP pursuant to section 8388.5(c)(2).*

Screen 3 Procedure. *The EUP must apply Screen 3 (Project Risk Analysis) to all Undergrounding Projects for which the Large Electrical Corporation has sufficient information. Projects that pass Screen 3 are reported as "Confirmed Projects."*

Screen 3 must be applied to a Portfolio of at least 25 individual Undergrounding Projects at the time of EUP filing.

Screen 4 Procedure. *The EUP must apply Screen 4 (Project Prioritization and Finalization) to all Confirmed Projects at the time of EUP filing. Projects that pass Screen 4 are "Prioritized Projects."*

The Large Electrical Corporation must detail the implementation approach it will use for each screen. The general requirements of each screen, including the minimum data and information requirements, are further described in the Sections below.

Our description of the Project progression through the four screens is discussed in Section D below.

2. Incorporating Changes (EUP Guidelines Section 2.4.2)

a. Changes to Circuit Segment (EUP Guidelines Section 2.4.2.1)

After the EUP is filed, the Large Electrical Corporation must account for new information (such as project-specific information obtained through scoping and other project work), model version and calibration changes (such as those detailed in Section 2.7.5.2), and updates to HFTD maps or new Wildfire Rebuild Areas.

In each Progress Report, the list of Circuit Segments provided to Energy Safety, and associated risk scores, must be the same list and scores used at that time by the Large Electrical Corporation for risk modeling and decision-making. This list, at minimum, must include changes to risk scores through completion of Undergrounding Projects performed via the EUP, or any other wildfire mitigation activity.

Additionally, risk scores for each Circuit Segment must be updated to account for modeled effects of application of the EUP and other wildfire mitigation/hardening, until such time as a model calibration or version update takes place and assigns new risk scores directly.

If any changes occur on a Circuit Segment before it has passed Screen 3, then Screen 1 and Screen 2 must be reapplied. This could result in Circuit Segments being added or removed from the EUP. The Out-of-Area Circuit Segment list, In-Area Circuit Segment list, Eligible Circuit Segment list, Ineligible Circuit Segment list, and the list of Undergrounding Projects must all be updated. Information in the Screen 2 comparison must also be updated.

The EUP narrative must describe the process the Large Electrical Corporation will use to update this information in Progress Reports.

In compliance with the EUP Guidelines, PG&E's Progress Reports will account for new information, model changes and other updates that affect relevant Circuit Segments.

When PG&E performs risk model updates, we will update the Baseline risk values to account for changes to risk scores due to work implemented in all system hardening programs, including the EUP, non-EUP undergrounding, overhead hardening, and line removal. PG&E will apply the risk reduction achieved from system hardening to the pre-mitigation risk scores to account for the risk value change on the Circuit Segment. Risk reduction achieved from Subprojects will be applied on a pro-rata basis. PG&E will account for risk reduction only after a Project has passed Quality Assurance (QA) review, which is a key step in confirming the construction is complete and the underground

assets are operational. PG&E will provide annual updates to risk scores in our Progress Report.

The Wildfire Distribution Risk Model (WDRM), Outage Program Risk Model (OPRM), and associated Wildfire Benefit Cost Analysis (WBCA) are based on a defined snapshot of system conditions, risk information, and mitigation status at a point in time. As new versions of these models are developed, the underlying snapshots are refreshed to incorporate updated information available at the time of the model update. Such updates may include revisions to High Fire Threat District (HFTD) boundaries approved by the CPUC, updates to work completed in Fire Rebuild Areas, completed mitigation activities, changes in asset conditions or configurations, and other updates affecting model inputs.

PG&E may update Circuit Segment risk scores reported in Progress Reports to reflect score changes due to updated model versions and refreshed data snapshots in addition to risk reductions directly attributable to EUP Undergrounding Projects or other system hardening activities. To the extent that completed mitigation measures, whether associated with system hardening programs or other risk reduction programs, are reflected in the updated model snapshot, the resulting risk score changes will be incorporated into the WDRM and OPRM and, in turn, the WBCA outputs used for EUP reporting and decision making. PG&E will incorporate the updated risk scores in future Progress Reports.

If changes occur on a Circuit Segment before it has passed Screen 3, we will re-evaluate the Circuit Segment risk scores by reapplying Screen 1 and Screen 2 (to reconfirm eligibility and Benefit-Cost Ratio (BCR) values for alternative mitigations). During the Screen 3 review process, PG&E will determine if system hardening has already occurred on a Circuit Segment or portion of a Circuit Segment through a non-EUP system hardening Project. Any Circuit Segments or portions of a Circuit Segment that have previously been hardened will be removed from EUP eligibility (see Figure 3-5, High Level Feasibility Review). Additionally, when PG&E issues a new version of the WBCA, we will rerun Screen 1 and Screen 2 and re-evaluate Circuit Segments

that have not passed Screen 3. Once a Project has passed Screen 3, the Project will be considered a Confirmed Project and will be developed for construction. Any future updates, including risk model updates, will not change the status of Confirmed Projects.

PG&E describes our timing and process for issuing new versions of our risk models in Chapter 8, Section C (EUP Guidelines Section 2.7.6).

b. Subprojects (EUP Guidelines Section 2.4.2.2)

During the scoping process, the Large Electrical Corporation may divide an Eligible Circuit Segment into one or more Subprojects. Subprojects may be created for operational reasons, such as differences in expected completion times of portions of the undergrounding work (referred to as Undergrounding Subprojects). Subprojects may also be created to reflect that a portion of the Circuit Segment will be treated with a different wildfire mitigation (referred to as a non-undergrounding Subproject). If a Circuit Segment does not have multiple Subprojects during the scoping process, then it should be reported as a single Subproject.

The EUP narrative must include a detailed description of the decision-making process the Large Electrical Corporation will use to determine when to divide a Circuit Segment into Subprojects. This narrative must include a list of possible reasons for division, with a detailed explanation of each.

PG&E selects mitigations by looking at the Circuit Segment as a whole. These Circuit Segment level mitigations together are defined as a System Hardening Project. We select the Project-level mitigations using the process described in Section D.2 below. A Project that includes more than one type of mitigation, or a hybrid of mitigations, is segmented into Subprojects based on the type of mitigation. Thus, while a Project may include multiple mitigations, a Subproject can only involve one mitigation type. During Project scoping, PG&E may divide an Eligible Circuit Segment into one or more Subprojects to differentiate by mitigation and to record the cost of the Subproject to the correct funding, as outlined below:

- Funding Sources: Undergrounding will exclusively be funded through the EUP while non-EUP system hardening (i.e., Overhead Hardening, Remote Grid, and Line Removal) will continue to be funded in the General Rate Case (GRC). Projects are divided into Subprojects to identify and manage funding source differences.

- Remote Grids: Remote Grids are implemented on small sections of Circuit Segments. They are often developed, estimated, and constructed with different resources than undergrounding or overhead hardening and can have longer lead time dependencies due to the type of customer interaction and agreements required.
- Different County: Cost and tax implications vary by county. We separate Projects into Subprojects if the Project (i.e., Circuit Segment) spans multiple counties so that county-specific accounting requirements can be correctly applied.

3. Other Anticipated Changes (EUP Guidelines Section 2.4.2.3)

The Large Electrical Corporation must provide a narrative describing any other expected or known changes likely to occur and how those changes will be incorporated into the EUP.

PG&E does not currently anticipate any changes to the EUP other than potential changes to the CPUC's HFTD map discussed in Section D.1.a.3 if PG&E files a Petition for Modification (PFM) that results in an expansion of the HFTD. Expansion of the HFTD would potentially allow other Undergrounding Projects to be included in the EUP.

Should new information arise or circumstances change, including changes arising from the SPD-37 proceeding (A.26-02-005) or other changes in regulatory requirements, changes to cost estimates, or the development of new technologies, PG&E would seek to revise the EUP, respond as directed to a regulatory request or requirement to modify the EUP, and/or provide updated information in Progress Reports, as appropriate. PG&E remains committed to ongoing evaluation and transparency so that changes are documented and integrated in accordance with EUP Guidelines, reporting requirements, and internal processes.

4. Physical Changes to a Circuit Segment (EUP Guidelines Section 2.4.2.4)

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. These changes are accounted for in three ways.

First, the Circuit Segments must be represented by unique identification names, which are unique both spatially and temporally, meaning a name 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 between Circuit Segments (e.g., circuit breakers and reclosers) are moved, removed, or added. See the introduction of Appendix C.1 for details.

Second, the evolution of Circuit Segments is tracked in the Circuit Segment Changelog table, linking the prior Circuit Segment ID to the new one (See Section C.1.7 of Appendix C).

Third, a Confirmed Project is defined by the boundaries of the Confirmed Project Polygon that encompasses the entire Circuit Segment on which the Undergrounding Project is defined. The Confirmed Project Polygon is fixed once the Circuit Segment becomes a Confirmed Project. Further details on the Confirmed Project Polygons are defined in Appendix C.4.2. Changes to proposed work on each Undergrounding Project do not need to be re-evaluated or passed through the screens again due to a physical change to the underlying Circuit Segment unless the work would take place outside the Confirmed Project Polygon, in which case additional justification will be required. Any Project or Subproject which has assets outside of the Confirmed Project Polygon must have a justification in the C.1.14 Subproject Table.

The EUP narrative must describe the process the Large Electrical Corporation will use to update this information in Progress Reports.

PG&E will account for physical changes to a Circuit Segment. PG&E developed a mapping tool called the Circuit Segment Version Comparison tool for tracking changes to Circuit Segments between risk model versions. The tool considers comparative geometries and equipment asset relationships to determine how each Circuit Segment has changed between WDRM versions. For a WDRM version, each Circuit Segment is assigned a unique name which is reported as [circuit_segment_id]. Starting with WDRM v5, all Circuit Segments will receive a new unique ID for each new model version by appending the model version number to the end of the Circuit Segment name, e.g., "circuit_segment_id" in WDRM v5 snapshot will be represented as "circuit_segment_idv5". Each new ID will be traceable to

the ‘parent’ Circuit Segment ID(s) in the previous risk model version snapshot.

The output from the Circuit Segment version comparison tool will be used to populate the Circuit Segment Changelog Table (to be included in the Progress Report as Table C.7). This table will document significant changes in Circuit Segment configurations between model versions, as specified in the EUP Guidelines, by examining key attributes to identify and categorize changes.

The Circuit Segment attributes used to determine configuration changes between versions include:

- Circuit Segment names;
- Feeder Names/IDs;
- Interrupting Device Operating IDs;
- Primary and Secondary Overhead Conductor lengths; and
- Conductor Asset IDs and counts.

To determine the change type for the Circuit Segment Changelog Table, PG&E will compare conductor asset IDs on Circuit Segments between snapshots. If conductors on a Circuit Segment appear on multiple Circuit Segments in a subsequent snapshot, the change cause will be categorized as a “split.” If conductors on multiple Circuit Segments appear on a single Circuit Segment in a subsequent snapshot, the change cause will be categorized as a “merge.”

We will provide the first Circuit Segment Changelog Table to Energy Safety in the first Progress Report following an update to the WBCA model (which includes the relevant WDRM and Outage Program Risk Model updates).

Confirmed Project Polygons are included as part of our Geographic Information System (GIS) data in Progress Report 0. (*See* Progress Report, Attach. A-5, Table C.17). PG&E will not update a Confirmed Project Polygon and will consider it fixed. In the event an update to a risk model adds additional assets into the same area, that new Circuit Segment would be evaluated based on our Screen 3 criteria, with the assets included in the previously Confirmed Project, being excluded from the analysis. (See discussion below in Section D.3.a)

D. PG&E's Project Acceptance Framework

In the following sections, PG&E describes our Project Acceptance Framework. These descriptions align with the process flow diagrams that show the different steps, processes, and decisions associated with each stage of the Project Acceptance Framework.[81] Because the process flow diagram is very large, we present it in smaller sections aligned to:

- Screen 1: Section D.1, Figure 3-1 (EUP Guidelines Section 2.4.3)
- Fire Rebuild: Section D.1.a, Figure 3-2 (EUP Guidelines Section 2.4.3.1)
- Screen 2: Section D.2, Figure 3-3 (EUP Guidelines Section 2.4.4)
- Screen 3: Section D.3, Figure 3-4 through Figure 3-8 (EUP Guidelines Section 2.4.5)
- Screen 4: Section D.4, Figure 3-9 (EUP Guidelines Section 2.4.6)

Further, PG&E includes a limited number of previously-scoped Projects whose construction has been delayed in the Project Acceptance Framework, Section D.5 below.

1. Screen 1: Circuit Segment Eligibility (EUP Guidelines Section 2.4.3)

Screen 1 (Circuit Segment Eligibility) is the procedure within the Project Acceptance Framework that identifies relevant Circuit Segments and creates the List of Eligible Circuit Segments.

Figure 3-1 below shows the Screen 1 procedures within the Project Acceptance Framework that we use to determine if a Circuit Segment is eligible for the EUP.

Screen 1 begins by reviewing the list of all electric distribution primary overhead Circuit Segments (also referred to as circuit protection zones or CPZs) in PG&E's service territory to determine which are relevant to the EUP. Circuit Segments in Tier 2 or 3 of the HFTD or in a Fire Rebuild Area are In-Area Circuit Segments and may be considered for the EUP. All other Circuit Segments are excluded from consideration.

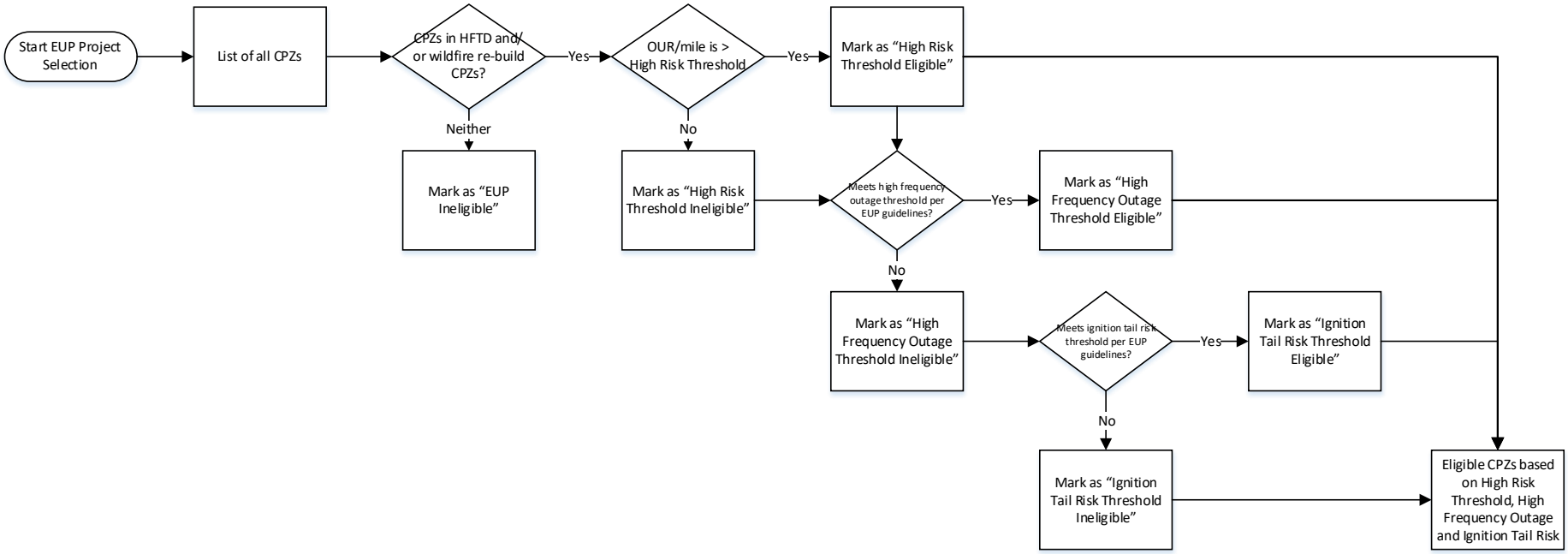
Next, to determine EUP eligibility, PG&E reviews the relevant Circuit Segments against the following three risk thresholds: (1) the High-Risk Threshold; (2) the High Frequency Outage Program Threshold; and the

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[81] Attach. B, WP003 (Project Prioritization and Decision Tree).

(3) Ignition Tail Risk Threshold. If a Circuit Segment meets one or more of the thresholds, it is considered “high risk” and passes from Screen 1 to Screen 2 for further evaluation.

FIGURE 3-1:
PROJECT ACCEPTANCE FRAMEWORK – SCREEN 1



a. Identification Of Circuit Segments Inside and Outside of a Tier 2 or 3 High Fire Threat Districts and Fire Rebuild Areas (EUP Guidelines Section 2.4.3.1).

In Screen 1, the Large Electrical Corporation must identify all Circuit Segments in its service territory (All Circuit Segments) and specify which Circuit Segments are located in a Wildfire Rebuild Area or Tier 2 or 3 High Fire-Threat District ("In-Area Circuit Segments"). If a Circuit Segment has portions both within and outside of a Tier 2 or 3 HFTD, each span crossing the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may be considered for undergrounding.

For each Circuit Segment, the following risk scores must be reported: Overall Utility Risk Score; Ignition Consequence Score; and Outage Program Likelihood Score. Section 2.7.9 of these Guidelines details the requirements for these risk scores. Additionally, each Circuit Segment must be identified by location, indicating whether the Circuit Segment is in a Tier 2 or 3 High Fire-Threat District; in a Wildfire Rebuild Area; or not located in either a Tier 2 or 3 HFTD or a Wildfire Rebuild Area. Appendix C.1.6, Circuit Segment Identification Table, and C.1.8, Circuit Segment Risk Score Table, give instructions for the type of information required in Screen 1.

The EUP narrative must describe the process the Large Electrical Corporation will use to identify Wildfire Rebuild Areas and the corresponding affected Circuit Segments. The Large Electrical Corporation must include a narrative in the Progress Reports describing identified Wildfire Rebuild Areas and providing information on the wildfire date, time, location, affected Circuit Segments and facilities impacted. The narrative must indicate if any distribution infrastructure damaged in the wildfire has already been rebuilt. Only Circuit Segments that have been damaged by wildfire and have not previously been rebuilt are eligible.

The EUP must include the following information in the EUP narrative or an additional table:

a. The total number of Circuit Segments within the Large Electrical Corporation service territory;

b. The total number of Circuit Segments located within a Tier 2 or 3 HFTD;

c. The total number of Circuit Segments located within a Wildfire Rebuild Area; and

d. The total mileage of lines in all Circuit Segments in each of the above groups.

In the EUP narrative, the Large Electrical Corporation must create three lists of In-Area Circuit Segments sorted in descending order by:

a. Overall Utility Risk Score;

b. Ignition Consequence Score; and

c. Outage Program Likelihood Score. Each list should be shown as a table with only the top 20 highest scoring Circuit Segments, containing all three risk scores, the county where the Circuit Segment is located, and the Tier 2 or 3 HFTD Tier or Wildfire Rebuild Area that applies to the Circuit Segment.

1) Process Used to Identify Circuit Segments in a Tier 2 or 3 High Fire-Threat District

PG&E identifies In-Area HFTD Circuit Segments by reviewing electrical distribution assets within HFTD boundaries. This review is conducted by overlaying our GIS system data (detailed spatial information about the location and configuration of electrical infrastructure) with the HFTD maps published by the California Public Utilities Commission (CPUC or Commission). PG&E identifies all Circuit Segments that are either fully or partially located within Tier 2 or Tier 3 HFTD areas. For Circuit Segments that traverse the boundaries of HFTD zones, each span that crosses into or out of a Tier 2 or Tier 3 HFTD is reviewed, and it is confirmed that only up to two adjacent spans outside the HFTD would be eligible for evaluation and potential undergrounding, consistent with the EUP Guidelines.[82]

2) Process Used to Identify Circuit Segments in Fire Rebuild Areas[83]

PG&E implemented two processes to identify Circuit Segments damaged by wildfire. The first process identifies Circuit Segments where previous Fire Rebuild hardening work occurred. The second process identifies Circuit Segments with Electric Corrective (EC) tags from fires spanning 2015 to 2025.[84] Taken together, the Circuit Segments from both processes represent the population of Circuit Segments with a PG&E asset that was damaged by wildfire.

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82 "If a Circuit Segment has portions both within and outside of a Tier 2 or 3 HFTD, each span crossing the Tier 2 or 3 HFTD boundary and up to two adjacent spans outside of a Tier 2 or 3 HFTD may be considered for undergrounding." EUP Guidelines, Section 2.4.3.1, p. 16.

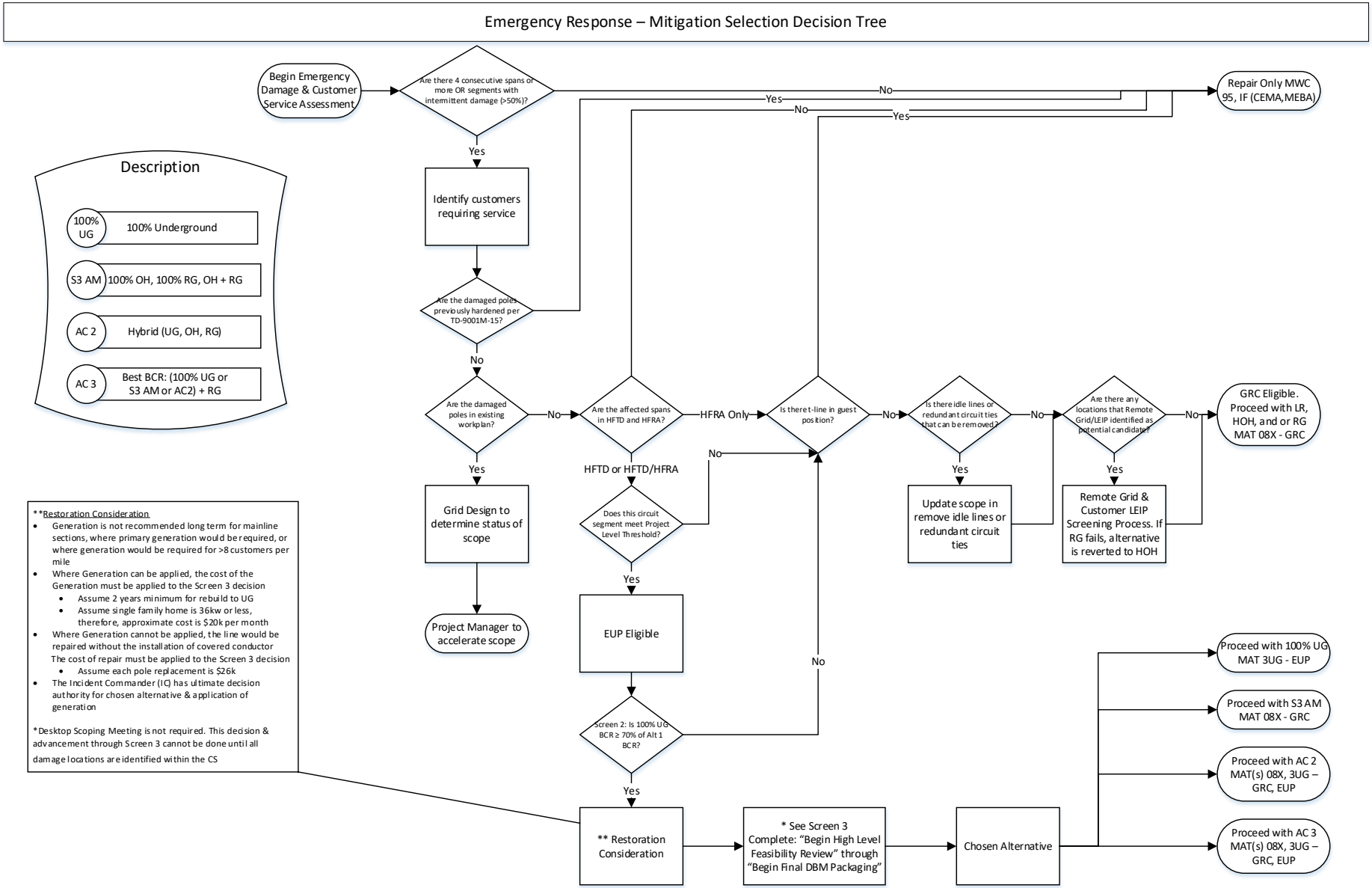
83 While the EUP Guidelines reference "Wildfire Rebuild Areas," PG&E uses the term "Fire Rebuild Areas," which we define specifically as four or more spans of electric distribution infrastructure damaged by a fire.

84 The geospatial alignment included a five-meter buffer given the changes in Circuit Segment configuration since 2015.

PG&E identified 844 Circuit Segments, of which 581 are in a Fire Rebuild Area in the HFTD. These Circuit Segments will follow the Project Acceptance Framework outlined in this chapter.

Immediately after a wildfire, PG&E conducts a damage assessment and determines if damaged assets require hardening. Damaged assets that require hardening are considered for Fire Rebuild. System hardening is deployed where significant rebuilding is required (e.g., four or more spans and/or segments with intermittent damage). In this case, PG&E will add the Circuit Segments to the population of Fire Rebuild Circuit Segments in the HFTD and provide all required information about the wildfire and impacted facilities in the Progress Report. Circuits Segments identified in this way are potential Fire Rebuild Projects. It is important to note that not all Circuit Segments that are in a Fire Rebuild Area are potential Fire Rebuild Projects. A Circuit Segment is only prioritized as a Fire Rebuild Project if it is reviewed according to the damage assessment process described in this paragraph and in Figure 3-2 below.

FIGURE 3-2:
PROJECT ACCEPTANCE FRAMEWORK – EMERGENCY RESPONSE



In Sections D.2 through D.4 below (addressing EUP Guidelines 2.4.4 to 2.4.6), we detail how we apply the four screens to a Circuit Segment in a Fire Rebuild Area. There are several differences in how Fire Rebuild Circuit Segments progress through Screens 3 and 4 compared to a non-Fire Rebuild Circuit Segment.

- Screen 1: No Difference – Fire Rebuild Circuit Segments are eligible for the EUP if they meet one of the Project Level Thresholds (see Chapter 7, Section M for details of Project Level Thresholds).
- Screen 2: No Difference – Calculate BCR for: (1) 100 percent Underground; (2) Alternative Mitigation 1; (3) Alternative Mitigation 2; and (4) Additional Comparison. See Table 3-9 below for a detailed description of the Screen 2 mitigation comparison types.
- Screen 3: If undergrounding has the highest BCR or is within the BCR uncertainty factor,[85] PG&E proceeds through the full Screen 3 analysis to scope multiple mitigations and determine the appropriate, permanent mitigation. See Table 3-9 below for a detailed description of the Screen 3 mitigation comparison types.
- Screen 4: Fire Rebuild Projects are given priority over other Circuit Segments in Screen 4, regardless of the calculated priority of the Circuit Segment, due to the time sensitivity of rebuilding assets after they have been damaged by fire. Not all Circuit Segments in a Fire Rebuild Area are considered Fire Rebuild Projects, only those Circuit Segments that have been through the damage assessment process shown in Figure 3-2.

As required by the EUP Guidelines Section 2.4.3.1, PG&E will include a narrative describing identified Fire Rebuild Areas in our Progress Reports. Future Progress Reports will identify Fire Rebuild Areas and provide information on the wildfire data, time,

[85] The BCR uncertainty factor is discussed in Section D.3.a.6 below (Benefit-Cost Comparison).

location, affected Circuit Segments, and facilities impacted. PG&E's narrative in Progress Report 0 and in future Progress Reports will indicate if any distribution infrastructure damaged in the Fire Rebuild Areas has already been rebuilt since only Circuit Segments that have not previously been rebuilt are eligible.

3) Total Number of Circuit Segments and Mileage in the Service Territory, in Tier 2 or Tier 3 HFTD or Fire Rebuild Area

Table 3-3 shows the total number of Circuit Segments and associated mileage in PG&E's service territory, as well as in Tier 2 and Tier 3 HFTD, and in non-HFTD Fire Rebuild Areas.

TABLE 3-3:
CIRCUIT SEGMENT IDENTIFICATION

Line No.	Category	No. of Circuit Segments	Primary Overhead Mileage
1	Service Territory	11,482	80,632
2	Tiers 2 or/and 3 HFTD + All HFRA	3,737	25,709[(b)]
3	Tiers 2 or/and 3 HFTD + Contiguous HFRA[(a)]	3,650	25,381[(b)]
4	Non-HFTD Fire Rebuild Areas	263	38[(b)]

(a) Omits high risk Circuit Segments located entirely within HFRA. Includes Circuit Segments that traverse HFTD and HFRA.

(b) Includes miles only in HFRA, HTFD Tier 2 and/or Tier 3.

High Fire Risk Areas (HFRAs) refer to regions identified by PG&E where the risk of a utility triggered catastrophic wildfire from an offshore wind event is higher, including areas not currently designated within the HFTD. These regions were identified using historical and recent fire data, subject matter expertise, climatology, and fire spread models.

PG&E does not plan to nominate any mileage entirely outside of the HFTD other than non-HFTD adjacent two spans for inclusion in the EUP unless the CPUC approves incorporating such areas into the HFTD or otherwise updates the HFTD maps. Consistent with this approach, PG&E may file with the CPUC a Petition for Modification (PFM) to update the HFTD areas across our service

territory. The PFM would request that certain HFRA polygons be incorporated into the HFTD to enable consideration of the most effective mitigation strategies in those high-risk areas.

PG&E has identified 87 high risk Circuit Segments located entirely within HFRA (i.e., outside HFTD Tier 2 or Tier 3 and not within Fire Rebuild Areas). Consistent with the EUP Guidelines, these Circuit Segments are not included in the Screen 1 Circuit Segment Eligibility list. If a PFM is approved, or the HFTD maps are otherwise updated, PG&E will re-run Screen 1 to reflect the revised set of Eligible Circuit Segments.

PG&E considers Circuit Segments that traverse both HFTD and non-HFTD areas for Screen 1 eligibility; however, only the portions within the HFTD, plus the allowed non-HFTD adjacent two spans, can be included in an Undergrounding Project.

4) The 20 highest scoring Circuit Segments of Each List (Overall Utility Risk Score, Ignition Consequence Score, Outage Program Likelihood Score)

The tables below list the 20 highest scoring Circuit Segments based on three types of risk. Table 3-4 is based on the Monetized Overall Utility Risk score per HFTD mile; Table 3-5 is based on the Monetized Ignition Consequence risk score; and Table 3-6 is based on the Outage Program Likelihood risk score.

TABLE 3-4:
TOP 20 IN AREA CIRCUIT SEGMENTS SORTED IN DESCENDING ORDER BY MONETIZED OVERALL UTILITY RISK SCORE PER HFTD MILE

Line No.	Circuit Segment	Overall Utility Risk Score per HFTD mile (2028, $M)	Ignition Consequence (2028, $M)[a]	Outage Program Likelihood Score (Minutes/Year)	County[b]	HFTD Tier/ Fire Rebuild Area
1	SILVERADO 2105CB	2637.197	0.680	487	Napa	Tier 3
2	BRUNSWICK 1110CB	1140.067	0.500	111	Nevada	Tier 2
3	BRENTWOOD 2105B534R	542.498	0.524	615	Contra Costa	Tier 2
4	TEMPLETON 2113CB	381.220	0.521	1988	San Luis Obispo	Tier 2
5	SANTA YNEZ 1104CB	267.017	0.599	410	Santa Barbara	Tier 2
6	SAN RAFAEL 1109535284	255.467	0.846	7	Marin	Tier 2
7	MARIPOSA 2102594143	205.435	5.734	253	Mariposa	Tier 2
8	SAN LUIS OBISPO 1108CB	193.618	0.625	21	San Luis Obispo	Tier 2
9	PUEBLO 2102698	164.107	0.591	3075	Napa	Tier 2
10	PEABODY 2113CB	148.788	0.709	724	Solano	Tier 2
11	RED BLUFF 1103CB	117.626	0.506	1484	Tehama	Tier 2
12	FROGTOWN 170232556	101.361	3.118	86	Calaveras	Tier 2
13	BRUNSWICK 111095576	98.890	0.683	137	Nevada	Tier 2
14	PLACER 1103238990	97.065	0.547	339	Placer	Tier 2
15	SONOMA 1105138	92.015	0.532	1195	Sonoma	Tier 2
16	SAUSALITO 11021224	86.628	0.552	56	Marin	Tier 2
17	GABILAN 11013034	85.732	0.534	1327	Monterey	Tier 2
18	SAN LUIS OBISPO 1105CB	84.273	0.534	39	San Luis Obispo	Tier 2
19	SILVERADO 210298998	81.406	0.711	1350	Napa	Tier 2
20	DUNBAR 1103CB	79.107	0.676	258	Sonoma	Tier 2

(a) This is the monetized Ignition Consequence score.

(b) County is derived from a geospatial analysis which determines which County contributes the largest overlap to the Circuit Segment.

TABLE 3-5:
TOP 20 IN AREA CIRCUIT SEGMENTS SORTED IN DESCENDING ORDER BY MONETIZED IGNITION CONSEQUENCE

Line No.	Circuit Segment	Overall Utility Risk Score per HFTD mile (2028, $M)	Ignition Consequence (2028, $M)[a]	Outage Program Likelihood Score (Minutes/Year)	County[b]	HFTD Tier/ Fire Rebuild Area
1	BALCH NO 1 1101CB	3.592	623.901	4	Fresno	Tier 2
2	BALCH NO 1 1101406582	0.538	393.806	81	Fresno	Tier 2
3	BALCH NO 1 1101105414	0.652	346.581	165	Fresno	Tier 2
4	WILDWOOD 1101384582	0.338	246.472	129	Shasta	Tier 2
5	CUYAMA 1103684566	0.200	242.510	151	San Luis Obispo	Tier 2
6	TASSAJARA 21123202	0.778	237.633	189	Contra Costa	Tier 3
7	TIGER CREEK 0201CB	2.101	222.760	448	Amador	Tier 3
8	CALPINE 1144960	0.176	193.644	0	Lake	Tier 3
9	CALPINE 1144276-G	2.452	192.780	2	Sonoma	Tier 3
10	KESWICK 1101417066	0.496	184.384	1571	Shasta	Tier 3
11	TIGER CREEK 0201320746	0.227	175.107	444	Amador	Tier 3 & 2
12	CALPINE 1146400	0.112	168.090	25	Sonoma	Tier 3
13	FRENCH GULCH 11011892	0.272	166.651	246	Shasta	Tier 2
14	TEJON 11023760	0.154	159.662	126	Kern	Tier 2
15	CALISTOGA 110135588	0.478	156.943	1757	Napa	Tier 3
16	CALPINE 1146CB	0.180	146.273	93	Sonoma	Tier 3
17	MADISON 1105995448	0.218	142.162	1592	Yolo	Tier 2
18	BALCH NO 1 1101R372	0.150	141.626	73	Fresno	Tier 2
19	MONTICELLO 1101130412	0.412	139.326	2472	Napa	Tier 2
20	CALAVERAS CEMENT 1101544800	0.128	131.960	344	Calaveras	Tier 2

(a) This is the monetized Ignition Consequence score.

(b) County is derived from a geospatial analysis which determines which County contributes the largest overlap to the Circuit Segment.

TABLE 3-6:
TOP 20 IN AREA CIRCUIT SEGMENTS SORTED IN DESCENDING ORDER BY OUTAGE PROGRAM LIKELIHOOD

Line No.	Circuit Segment	Overall Utility Risk Score per HFTD mile (2028, $M)	Ignition Consequence (2028, $M)[(a)]	Outage Program Likelihood Score (Minutes/Year)	County[(b)]	HFTD Tier/ Fire Rebuild Area
1	DUNBAR 1103234	1.069	10.980	14859	Sonoma	Tier 3 & 2
2	CEDAR CREEK 1101CB	0.165	25.890	14238	Shasta	Tier 3 & 2
3	REDBUD 1102523244	0.802	14.835	13058	Lake	Tier 3 & 2
4	MIDDLETOWN 1101548	0.357	24.760	11801	Lake	Tier 3 & 2
5	CORTINA 1101302192	2.334	13.641	11092	Colusa	Tier 2
6	VACAVILLE 1111CB	1.988	2.967	10995	Solano	Tier 2
7	SILVERADO 2104806500	0.619	18.718	10965	Napa	Tier 3
8	VOLTA 11011596	0.246	24.971	10486	Tehama	Tier 2
9	STILLWATER 11011320	0.323	14.860	10136	Shasta	Tier 2
10	ELK CREEK 11012002	0.569	11.070	10037	Glenn	Tier 2
11	BIG BEND 1101CB	0.351	84.736	9554	Butte	Tier 3
12	MIDDLETOWN 1101644756	0.347	78.738	9326	Lake	Tier 3 & 2
13	APPLE HILL 2102836878	0.572	17.870	9317	El Dorado	Tier 3 & 2
14	PARADISE 1105CB	0.757	6.190	8926	Butte	Tier 3
15	BANGOR 110131502	0.125	3.269	8629	Butte	Tier 2
16	MADISON 210189332	8.296	3.115	8514	Yolo	Tier 2
17	VACA DIXON 110118292	16.176	1.432	8402	Solano	Tier 2
18	LUCERNE 1106526	0.657	6.796	8345	Lake	Tier 2
19	VOLTA 1102CB	0.762	22.061	8270	Shasta	Tier 3
20	CALPINE 1144CB	0.185	114.630	8184	Sonoma	Tier 3 & 2

(a) This is the monetized Ignition Consequence score.

(b) County is derived from a geospatial analysis which determines which county contributes the largest overlap to the Circuit Segment.

b. Identification of Risky Circuit Segments and Mitigation Standards (EUP Guidelines Section 2.4.3.2)

Screen 1 (Circuit Segment Eligibility) ensures that the EUP limits eligibility to higher risk Circuit Segments. In the description of the Project Acceptance Framework, the EUP must present Project-Level Thresholds that establish the need for risk mitigation. Additionally, the Large Electrical Corporation must present Project-Level Standards that define a successful mitigation. Additional information on the required Project-Level Thresholds and Standards is provided in Section 2.7.9 of these Guidelines. The Project-Level Thresholds and Standards to be applied to Circuit Segments are:

1. ***Eligible Circuit Segment Thresholds:*** *the minimum risk score thresholds that will be used to identify Circuit Segments that are eligible for the 10-Year EUP. These thresholds are the High-Risk Threshold, Ignition Tail Risk Threshold, and High Frequency Outage Program Threshold. They are further detailed in 2.7.9.1. In-Area Circuit Segments that do not meet any of these thresholds are called Ineligible Circuit Segments.*
2. ***Mitigated Circuit Segment Standards:*** *the Project-Level risk score that an Eligible Circuit Segment must reach to be considered sufficiently mitigated under the terms of the EUP. These standards are the High-Risk Project Level Standard, the Ignition Tail Risk Project-Level Standard, and the High Frequency Outage Program Project-Level Standard. They are further detailed in 2.7.9.2.*

After determining these Project-Level Thresholds and Standards, the Large Electrical Corporation must evaluate the list of In-Area Circuit Segments to determine eligibility and minimum mitigation needs.

The following must be included in the narrative portion of the EUP:

a. The Project-Level Thresholds and Standards;

b. The total number of In-Area Circuit Segments;

c. The number of Eligible Circuit Segments, by category; and

d. The number of In-Area Circuit Segments that are below the eligibility thresholds (Ineligible Circuit Segments).

PG&E presents and describes the methodology used to determine the Project-Level Thresholds in Chapter 7, Section M.1 (EUP Guidelines Section 2.7.9.1). For reference, the Project-Level Thresholds are outlined in Table 3-7 below:

TABLE 3-7:
PROJECT LEVEL THRESHOLDS

Line No.	Project-Level Threshold	Value
1	High-Risk Project Threshold	$0.029M per primary OH mile
2	Ignition Tail Risk Threshold	$52.437M per ignition
3	High Frequency Outage Program Threshold	5,559 Outage Minutes Per Year

PG&E uses Project-Level Standards to define a successful system hardening mitigation. PG&E presents and describes the methodology used to determine the Project-Level Standards in Chapter 7, Section M.2 (EUP Guidelines 2.7.9.2).

Table 3-8 summarizes the EUP eligibility framework and the number of circuit segments and eligible miles associated with each eligibility threshold. The table identifies Circuit Segments that meet the High-Risk Project Threshold, Ignition Tail Risk Threshold, and High Frequency Outage Program Threshold, and presents the resulting counts of In-Area Eligible and Ineligible Circuit Segments. In-Area Ineligible Circuit Segments are those located within Tier 2 or Tier 3 HFTD or Fire Rebuild Areas that do not meet any of the three EUP eligibility thresholds. The counts included below are consistent with Attachment A-2, Tables C.6 and C.8.

Because a circuit segment may satisfy more than one eligibility threshold, the category counts are not additive. Circuit Segments that qualify under multiple thresholds are evaluated using the applicable project-level standard. For example, 93 of the 94 Ignition Tail Risk Threshold Circuit Segments and all 50 of the High Frequency Outage Program Threshold Circuit Segments are also eligible via the High-Risk Project Threshold. Therefore, PG&E has determined that these will be assessed through the High-Risk Project-Level Standard.

TABLE 3-8:
NUMBER OF ELIGIBLE CIRCUIT SEGMENTS BY CATEGORY

Line No.	Description	Description of Thresholds	Number of Eligible Circuit Segments	Miles of Circuit Segments in HFTD and HFRA [a]	Eligible Circuit Segment Miles in HFTD [b]
1	High-Risk Project Threshold (HRT)	$0.029M per mile	2,917[c]	20,852.7	20,618.4
2	Ignition Tail Risk Threshold	$52.437M per ignition	94	735.8	717.5
3	High Frequency Outage Program Threshold	5,559 Outage Minutes Per Year	50	671.8	670.5
4	High-Risk Project-Level Standard	OUR of Project Less than HRT	N/A	N/A	N/A
5	Tail Risk Project-Level Standard	90% Reduction in Ignition Tail Risk	N/A	N/A	N/A
6	High Frequency Outage Program Project-Level Standard	90% Reduction in Outage Program Risk	N/A	N/A	N/A
7	In-Area Eligible Circuit Segments	N/A	2,918	20,854.1	20,619.8
8	In-Area Ineligible Circuit Segments[d]	N/A	995	4,565.4	4,474.5

(a) Captures miles of Primary Overhead Circuit Miles in HFTD and HFRA, which is equivalent to the sum of data reported in the hftd_only_circuit_segment_length and hfra_only_circuit_segment_length fields in Table C.6 Circuit Segment ID Table.

(b) Eligible Miles are Primary Overhead Circuit Miles in HFTD, as reported in the hftd_only_circuit_segment_length field in Table C.6 Circuit Segment ID Table.

(c) This amount includes the Eligible Circuit Segments identified for the Ignition Tail Risk and High Frequency Outage Program Thresholds.

(d) Although this table primarily presents Eligible Circuit Segments, Line 8 reports In-Area Ineligible Circuit Segments and associated miles for completeness. In-Area Ineligible Circuit Segments are those that do not satisfy at least one of the three EUP eligibility thresholds.

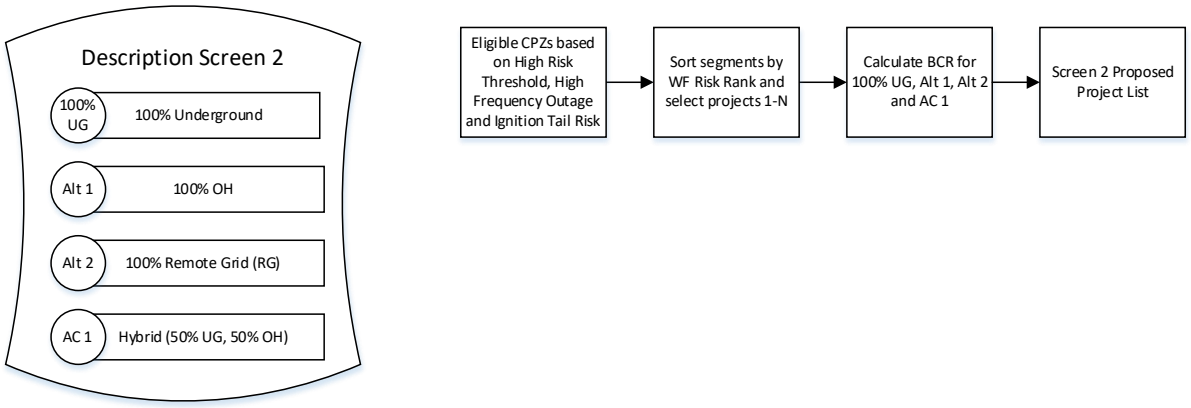
2. Screen 2: Project Information and Alternative Mitigation Comparison (EUP Guidelines Section 2.4.4)

Screen 2 (Project Information and Alternative Mitigation Comparison) confirms there is sufficient information available on a Circuit Segment and requires comparison of undergrounding to Alternative Mitigations in order to determine which Eligible Circuit Segments can be treated as Undergrounding Projects.

For Screen 2, the Large Electrical Corporation must conduct an analysis comparing undergrounding to Alternative Mitigations and provide the California Public Utilities Commission (CPUC) Cost Benefit Ratio (CBR) and all information in the CPUC Data Appendix 1 at the time the EUP is submitted to Energy Safety. The Alternative Mitigation Comparison must include a comparison of the project to at least two Alternative Mitigations as detailed in Section 2.7.10.

Figure 3-3 below shows a high-level version of PG&E's Screen 2 procedures for comparing Alternative Mitigations and Additional Comparisons using the BCR values for each.

FIGURE 3-3:
PROJECT ACCEPTANCE FRAMEWORK – SCREEN 2



Screen 2 Process

In Screen 2, PG&E calculates three high-level BCRs[86] for each Circuit Segment on the Screen 2 Circuit Segment list using the BCR methodology approved in CPUC Decision 25-08-032,[87] as well as an additional comparison:

1) 100 percent Underground: 100 percent Undergrounding (100 percent of the primary distribution line is undergrounded);
2) Alternative Mitigation 1: 100 percent Overhead Hardening (referred to as OH);
3) Alternative Mitigation 2: 100 percent Remote Grid with line removal; and
4.) Additional Comparison 1: Hybrid (50 percent of the Circuit Segment is undergrounded and the other 50 percent is overhead hardened).

Consistent with Energy Safety's requested baseline, the mitigation alternatives are evaluated relative to a baseline that includes applicable operational mitigations, including EPSS, DCD, and PSPS. Accordingly, operational mitigations are not treated as separate infrastructure alternatives or repeated in the name of each mitigation comparison. For example, Alternative Mitigation 1 is identified as “Overhead Hardening” because that name describes the permanent infrastructure treatment being evaluated. It does not mean that EPSS, DCD, or PSPS are excluded from the analysis. Rather, those operational controls are reflected in the baseline and continue to be deployed with overhead facilities as appropriate. While undergrounding eliminates the need for EPSS, DCD and PSPS on undergrounded facilities, mitigations such as overhead hardening generally continue to operate alongside EPSS, DCD, PSPS, and other operational measures when warranted by system conditions and wildfire risk.

The comparison types are more fully described below in Table 3-9. The costs included in the calculation are the capital construction costs and the ongoing capital and expense operations and maintenance costs, including

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86 These high-level BCR values are calculated at the Circuit Segment level and will be refined through the Screen 3 process.

87 The three IOUs propose that this methodology be approved for use in a utility EUP in their Joint Phase One Application 26-02-005, pp. 5-7.

lifetime vegetation management costs. The benefits included in the calculation include Ignition Risk reduction, Outage Program Risk reduction, Reliability Risk reduction, and safety risk reduction.[88]

Only Circuit Segments with a BCR equal to or greater than 1.0 for undergrounding are considered in Screen 3.[89]

a. Common Set of Values and Assumptions (EUP Guidelines Section 2.4.4.1)

Screen 2 (Project Information and Alternative Mitigation Comparison) may use common values and assumptions to develop estimates for Circuit Segments when project-specific information is not available. Screen 2 includes calculation of risk and benefit scores; it applies to both undergrounding and Alternative Mitigations. The EUP must include a narrative summarizing the assumptions underlying the values and explaining the metrics used in Screen 2. This narrative summary must be clear, concise, and comprehensive. At a minimum, this summary must include:

a. A description of the metrics required by the CPUC Guidelines for the SB 884 Program.

b. Detailed description of mitigations that the Large Electrical Corporation will use for these comparisons. Explanation of why these Alternative Mitigations are being considered. Description of the process and criteria that the Large Electrical Corporation will use for determining the best Alternative Mitigations for individual project comparisons. Description of the process for identifying and evaluating new mitigation technologies through the life of the EUP. Description of processes and resources that will be used for deploying each Alternative Mitigation.

c. Description of any assumptions for scope, cost, extent, and wildfire risk reduction and reliability improvements that are applicable to multiple Undergrounding Projects. These descriptions must be provided for all activities (undergrounding and Alternative Mitigations).

d. Explanation of how the need for additional easements, permits, and CEQA review are accounted for in the assumptions for scope, cost, extent, and risk reduction and reliability improvements.

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88 See Chapter 5 Section C.3 and Attach. B, WP006 (WBCA Whitepaper) for details of the BCR calculation and WBCA model.

89 In rare cases where Present Value (PV) of the lifetime cost savings exceed the PV of installation costs, the resulting BCR may be reported as a negative value due solely to the mathematical formulation of the ratio. Such outcomes represent economically favorable mitigations, as the effective cost-effectiveness asymptotically approaches infinity, and are therefore treated as exceeding the BCR ≥ 1.0 threshold for EUP eligibility.

1) Metrics Required by CPUC Guidelines for the SB 884 Program (EUP Guidelines Section 2.4.4.1(a))

On March 8, 2024, the CPUC approved Resolution (Res.) Safety Policy Division (SPD)-15, which included implementing guidelines for the SB 884 Program entitled *CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations* (SPD-15 Guidelines). The SPD-15 Guidelines address the process and requirements for CPUC review of any large electrical corporation's 10-year EUP funding application and conditional approval or denial of related costs.[90]

CPUC Resolution SPD-37 issued December 10, 2025 (SPD-37) modified the SPD-15 Guidelines. Resolution SPD-37 included new guidelines entitled *Update and Revision of Senate Bill 884 Program: CPUC Guidelines, Program for Expediting the Undergrounding of Distribution Equipment of Large Electrical Corporations SPD-37* (SPD-37 Guidelines). Appendix 1 to the SPD-37 Guidelines lists seven data tables that a utility is required to provide to the CPUC semiannually.[91] The CPUC's Safety Policy Division updated the *SB 884 Project List Data Requirements Guidelines* on May 11, 2026.[92]

We will include the seven data tables in Progress Report 0 (as Attach. A-6) and in subsequent reports. These data tables are described below.

- Table 1 – Data Set: Key elements and characteristics of a Project and/or Subproject including unique identifiers, mitigation plans, and associated risks.
- Table 2 – Capital Cost Breakdown: Capital costs associated with mitigation efforts.

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90 Res. SPD-37 (Dec. 10, 2025), pp. 1-2.

91 See Attach. D (CPUC / SPD 37 Data Tables).

92 Certain of the CPUC requirements are subject to change pending the outcome of the California Investor-Owned Utilities' Application 26-02-005.

- Table 3 – Risk Model Change Tracker: Documents changes to the risk models and how those changes affect the risk associated with the assets mitigated by the Project.
- Table 4 – HFTD and Associated Asset: Documents how low-risk associated assets are mitigated with the primary electric grid infrastructure.
- Table 5 – Financial Inputs: Financial parameters and metrics required to calculate and evaluate risk mitigations.
- Table 6 - Interruption Cost Estimate Calculator Inputs: Input parameters and data used to estimate customer interruption costs associated with reliability events.
- Table 7 – Annual Costs (Capital and Operation and Maintenance (O&M)) and O&M Savings Breakdown: Capital costs incurred before the Risk Reporting Unit (RRU or Project) becomes used and useful, and the O&M costs and savings incurred afterward, over the life of the asset.

2) Detailed Description of Mitigations Used for the Alternatives Comparison (EUP Guidelines Section 2.4.4.1(b))

Table 3-9 below describes the comparison types PG&E will use in Screens 2 and 3.

TABLE 3-9:
DESCRIPTION OF COMPARISON TYPES IN SCREEN 2 AND SCREEN 3

Screen 2	
Comparison Name[a]	**Description**
100% Underground (100% UG)	This comparison includes relocating existing high-risk overhead primary distribution lines underground. PG&E currently places underground both overhead distribution primary lines and those secondary and services lines that run parallel to the underground primary lines. Under this scenario, PG&E relies on overhead hardening for lateral secondary lines and services.
Alternative Mitigation 1 (Alt 1)	Covered conductor installation, also referred to as Overhead System Hardening, involves replacing bare overhead primary (high voltage) conductor and associated framing with conductor insulated with abrasion-resistant polyethylene coatings (sometimes referred to as tree wire).
Alternative Mitigation 2 (Alt 2) [b]	This alternative mitigation consists entirely of remote grid with line removal, where feasible. Remote grids provide utility service using standalone, decentralized energy sources and utility infrastructure for continuous, permanent energy delivery. PG&E selected the 100% Remote Grid alternative as Alternative Mitigation 2 because it is both feasible and appropriate for comparison purposes. PG&E previously removed certain Circuit Segments and implemented fully remote grid solutions, demonstrating the viability of this approach. In addition, PG&E believes that using homogeneous mitigation alternatives at Screen 2 provides the most logical, consistent, and transparent basis for comparing Alternative Mitigations.
Additional Comparison 1 (AC 1)	This additional design variation meets the requirements of the EUP Guidelines that this variation must meet or exceed the risk reduction of Alternative Mitigation 1. This additional design variation is a hybrid solution that consists of 50 percent underground and 50 percent overhead hardening.

Screen 3	
Comparison Name[a]	**Description**
100% Underground (100% UG)	Under the 100 Percent Underground scenario, there could be a small portion of a Project that is overhead hardened, if required for feasibility and operational reasons (e.g., transmission underbuilds).
Screen 3 Alternative Mitigation (S3 AM) [b]	This is the alternative mitigation with the best BCR of the non-undergrounding mitigations considered. Where feasible, this alternative may consist entirely of covered conductor, entirely of remote grid, or a combination of the two.
Additional Comparison 2 (AC 2) [b]	For Screen 3, this hybrid scenario will be updated to incorporate a more detailed project scope informed by the detailed scoping process (e.g., 40 percent underground, 60 percent overhead). This scenario may include undergrounding, overhead hardening and/or remote grid, where feasible.
Additional Comparison 3 (AC 3) [b]	This additional design variation is developed during the Screen 3 comparison and is considered where it is well-suited for a particular location. It is based on the best BCR of the other comparisons (100% UG, S3 AM, or AC 2 + Remote Grid, if feasible at this location).

(a) The comparison name identifies the permanent infrastructure mitigation. Applicable operational mitigations, including EPSS, DCD, and PSPS, are reflected in the baseline and are not separately identified in the name.

(b) Remote grid depends on factors including customer willingness to participate, site availability, land rights, environmental, permitting, engineering feasibility, and other considerations. Therefore, remote grid is generally treated as an add-on to a main hardening solution, rather than a required Screen 3 Alternative 2. Remote grid is considered in Additional Comparison 2, Additional Comparison 3, and when it improves upon or exceeds the BCR of a covered conductor project, is included in Screen 3 Alternative Mitigation.

a) Selection of Alternative Mitigations for Comparison Purposes

The comparisons listed in Table 3-9 above are considered as part of an alternative analysis because they address the comparative metrics requirements in EUP Guidelines Section 2.7.10. PG&E describes our process and criteria for determining the best mitigation for individual Project comparisons in Section D.3.a. of this chapter. In this section, we describe our typical Project scoping process, which outlines the process and criteria for determining the best alternatives that will be used for individual Project comparisons.

b) Process for Identifying and Evaluating New Mitigation Alternatives/Technologies Through the Life of the EUP

PG&E interprets the reference to “new mitigation technologies” to mean new mitigation alternatives that we would consider in Screen 2 and Screen 3. There are numerous new technologies aimed at increasing cost efficiency of existing mitigations such as Fluid Free Steerable Boring, Native Slurry Backfill, and Ground Level Distribution System/Minimum Cover Distribution System (GLDS/MCDS), but these do not represent new mitigations and therefore will not be discussed as part of this response. (Please refer to Chapter 5, Section C.3.c, for more information on new technologies aimed at increasing cost efficiency of existing mitigations.)

During the 10-year EUP period, PG&E may add new alternative mitigations into our Screen 2 and Screen 3 analyses if we identify a viable Alternative Mitigation technology or solution and have confirmed through product and pilot testing that it is suitable for deployment in PG&E’s service territory. PG&E has done this in the past, for example, when we included Remote Grids in our 2020 Wildfire Mitigation Plan (WMP) as a new technology that we identified as a viable alternative to conventional post-fire rebuild work in some locations. Since

installing our first remote grid in 2021, we have completed 17 installations (as of the end of 2025) and now include Remote Grids as one of our three core WMP system hardening initiatives, along with overhead hardening and undergrounding.

Throughout the EUP period, PG&E will continue our current practice of identifying and evaluating new wildfire and outage mitigation technologies and solutions through a multi-pronged approach that includes open innovation challenges, strategic industry partnerships, industry benchmarking, and rigorous testing.

c) New Mitigation Identification Process

PG&E identifies new and emerging mitigation opportunities by actively soliciting solutions from the global technology community to address specific operational challenges. This includes publishing R&D Strategy Reports[93] that outline "critical challenges" and inviting innovators to submit proposals. PG&E also hosts events such as the PG&E Innovation Summit to engage with technology leaders and startups, and sponsors competitions such as the XPRIZE Wildfire Competition to identify and test breakthrough mitigation technologies. PG&E participates in the Electric Program Investment Charge (EPIC) grant program by identifying promising startup projects and providing field expertise and real-world pilot opportunities. PG&E also meets with other utilities both within and outside the United States to exchange information, benchmark approaches, and share best practices for existing and emerging technological and operational mitigations.

d) New Mitigation Evaluation Process

Once potential mitigations are identified, PG&E conducts internal pilot testing and evaluation to determine whether a

93 PG&E R&D Strategy Report 2024, available at: <https://www.pge.com/assets/pge/docs/about/pge-systems/pge-rd-strategy-report-2024.pdf> (accessed June 5, 2026).

technology or solution is suitable for broader deployment in our service territory. When appropriate, PG&E partners with institutions such as the Electric Power Research Institute to conduct engineering and safety testing and product validation.

PG&E is currently implementing and evaluating several new technologies to support ongoing wildfire mitigation efforts including Continuous Grid Monitoring sensors and Early Fault Detection (EFD). Additional information on these technologies is provided in PG&E's 2026-2028 WMP.[94]

e) Processes Used to Deploy Alternate Mitigations.

The existing processes used to deploy undergrounding, Overhead System Hardening, Line Removal/Remote Grid and Hybrid Projects are outlined in Chapter 4, Sections D.2 and D.3.

PG&E describes the program resources that will be used to deploy undergrounding in Chapter 5, Section C.2, Workforce Development Plan. PG&E will use both internal and external resources to deploy other system hardening mitigations (Overhead System Hardening and Line Removal with Remote Grid). Internal resources often include PG&E's General Construction civil and line crews. External resources are contractors. Based on many years of experience, PG&E does not anticipate any resource constraints or special training required to execute Overhead System Hardening or Line Removal/Remote Grid.

3) Cost, Scope, and Risk-Reduction Assumptions Applicable to Undergrounding and Alternative Mitigation Projects (EUP Guidelines Section 2.4.4.1(c))

Assumptions related to Project scope (mitigation solution) and extent (location) for undergrounding, Overhead System Hardening, Hybrid Projects, and Line Removal/Remote Grid are described in

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94 PG&E 2026-2028 Wildfire Mitigation Plan R3, Vol. 1, (Dec. 30, 2025) (2026-2028 WMP), Table 10-1 and Section 12.1.1.

Section D.3.a.2 below where PG&E describes our typical project scoping and evaluation process.

PG&E uses the WBCA model and Feedback Loop[95] to evaluate Project costs, scope, extent, wildfire risk reduction, and reliability improvements that are applicable to undergrounding and the other mitigations we analyze in Screen 2 and Screen 3. The WBCA model considers: the forecast capital costs to construct a system hardening Project; the expected capital and expense O&M costs for the life of the asset; financing costs; Ignition Risk reduction and Outage Program reliability; the benefits period/asset life; rebuild costs for overhead assets; and the effectiveness of different mitigations. PG&E describes the WBCA model in Chapter 5, Section C.3.[96] Using the feedback loop, we evaluate different Project scope and extent variations.[97]

a) Screen 2 Metrics, Values and Underlying Assumptions

PG&E uses the WBCA model to evaluate Project costs, Wildfire Risk reduction, reliability improvements, and other public safety impacts that are applicable to undergrounding and the Alternative Mitigation and Additional Comparison that we analyze in Screen 2. We describe the WBCA in Chapter 5, Section C. PG&E's WBCA whitepaper[98] describes the assumptions underlying the values included in the WBCA and used to evaluate Projects in Screen 2.

PG&E developed the proposed Screen 2 Project list starting with the Eligible Circuit Segments based on the outputs from the Screen 1 analysis (Circuit Segments that are in the HFTD or Fire Rebuild Area and meet either the High-Risk Threshold, Ignition Tail Risk Threshold, or High Frequency Outage

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95 PG&E uses the Feedback Loop Model to compare and analyze different mitigations by updating the alternative scenarios with the most complete scope and cost assumptions available.

96 See Attach. B, WP006 (WBCA Whitepaper) for further detail.

97 See Attach. B, WP004 (WBCA Feedback Loop) for further detail.

98 See Attach. B, WP006 (WBCA Whitepaper) for further detail.

Program Risk Threshold). Eligible Circuit Segments are ranked from 1-to-N based on wildfire Risk Density.[99] Projects are then selected for Alternative Mitigation analyses sequentially starting with the highest-risk Circuit Segments.

PG&E considered the following metrics[100] when developing the BCR that is used to identify Projects to be included in the Screen 2 list (Table C.11 Screen 2).

1) Ignition Risk Reduction: Ignition Risk reduction estimates the amount of Ignition Risk that will be removed from PG&E's distribution system when a mitigation is applied to a Circuit Segment or portion of a Circuit Segment. The risk reduction is comprised of the initial risk on a Circuit Segment based on the WDRM and PG&E's estimated mitigation effectiveness.
2) Outage Risk Reduction: Outage risk reduction estimates the amount of outage risk—EPSS, PSPS, and Baseline outage risk—that will be removed from PG&E's electric distribution system when a mitigation is applied to a Circuit Segment or portion of a Circuit Segment. The risk reduction is comprised of the initial risk on a Circuit Segment that comes from the Outage Program Risk Model and PG&E's estimated mitigation effectiveness.
3) Safety Risk Reduction: Safety risk reduction quantifies the reduction in non-wildfire public safety risks associated with distribution infrastructure when a mitigation is implemented. The public safety risk reduction is comprised of the non-wildfire hazards to the public, such as contact with energized conductors, and vehicle collisions with utility poles.

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99 PG&E focuses on identifying Circuit Segments with the highest Wildfire Risk per mile. By ranking and selecting by risk per mile, we focus on Risk Density, i.e., the locations where the risk of wildfire is most concentrated.

100 Res. SPD-37 (Dec. 10, 2025), p. 6.

4) Mitigation Effectiveness: PG&E assesses the effectiveness of each Alternative Mitigation (underground, overhead hardening, etc.) relevant to the applicable risk category (ignition, outage, public safety) to estimate the amount of risk to be reduced (as a percentage of initial risk).[101]

5) Costs: The costs included in the BCR evaluation include the estimated capital installation costs along with the incremental (variance from Baseline) lifetime operations and maintenance costs for each mitigation. The estimated capital installation costs are derived from PG&E's historical remote grid installation costs and applied on a per customer basis.

Some Alternative Mitigation 2 Remote Grid projects will have a total cost of zero because Remote Grid costs are based on the number of customers served from overhead transformers located on the HFTD/HFRA portion of the Circuit Segment. PG&E currently has 154 Eligible Circuit Segments with zero costs. Of these, 80 have zero customers: 66 are short Circuit Segments that generally constitute spans between sectionalizing equipment, and 14 Circuit Segments are either circuit ties, customer owned facilities, or hydro generation distribution feeds where PG&E is the sole customer. Because these Circuit Segments have no customers, they are not viable Remote Grid projects and have no applicable costs. The remaining 74 Circuit Segments are on already-undergrounded transformers that are not candidates for further mitigation through remote grid, and therefore have no applicable cost.

Projects that have passed Screen 2 are included in Progress Report, Table C.11.

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101 See Attach. B, WP001 (Mitigation Effectiveness Analysis), for detailed methodologies and results of these assessments.

4) Assumptions Related to Easements, Permitting, and CEQA Review Affecting Scope, Cost, and Risk Reduction and Reliability Benefits (EUP Guidelines Section 2.4.4.1(d))

PG&E's scoping process (Screen 3) and Project execution planning (Screen 4 and beyond) consider the requirements to obtain easements, permits, and CEQA review. The number of required easements is an element of overall Project cost and is considered when developing cost assumptions. Permitting requirements are considered during mitigation selection and may influence where PG&E chooses to overhead harden or underground a distribution line. For example, if PG&E cannot secure an easement, we may need to re-route a hardening Project around that area.

Obtaining permits, easements, and CEQA reviews are considered long-lead activities and may impact Project schedules and the selection of undergrounding locations. The time required to secure easements for a system hardening Project is highly variable and permit acquisition times can be unpredictable. PG&E estimates the time required to secure easements, permits and/or conduct CEQA reviews based on prior history, and then works proactively to shorten the lead time and reduce the risk of delays from these activities. As the Project's scope is further defined, we are usually able to refine our estimates for securing easements, permits and/or conducting CEQA reviews.

Wildfire Risk reduction and reliability improvements are not impacted by additional easements, permits, and CEQA review other than in terms of Project timing. If a Project is delayed, PG&E may realize wildfire risk reduction and/or reliability improvements later than originally planned.

3. Screen 3: Project Risk Analysis (EUP Guidelines Section 2.4.5)

a. Screen 3 Procedure (EUP Guidelines Section 2.4.5.1)

Screen 3 (Project Risk Analysis) is the procedure for evaluating an individual Undergrounding Project in the context of the Portfolio of Undergrounding Projects and includes information obtained through the project development process. Screen 3 considers the expected wildfire risk reduction and reliability increase elements of the Plan Mitigation Objective of an Undergrounding Project and includes comparing risk metrics for undergrounding and Alternative Mitigations.

Screen 3 must be completed for each Undergrounding Project when the Large Electrical Corporation has sufficient information to fulfill the modeling requirements in Section 2.7 for that Undergrounding Project. Appendix C.1.12, Screen 3 Table, and C.1.15, Project Index Table, give instructions for the type of information required for Screen 3.

The EUP must contain a narrative detailing how the Large Electrical Corporation will use Screen 3 on individual Undergrounding Projects and describe the typical scoping process. The narrative must include the Screen 3 procedure for selecting Alternative Mitigations consistent with the instructions on Alternative Mitigation selection in Section 2.7.10. The narrative must include a description of how project-specific information will be incorporated into the selection of Alternative Mitigations. The narrative must include a description of how Baseline values will be determined per Section 2.7.5, Core Capability 6. The narrative must describe how the scoping process will be used to determine what portions of an Eligible Circuit Segment will be undergrounded.

For each Undergrounding Project with Subprojects, Appendix C.1.14, Subproject Table, requires the mitigation for each Subproject and a narrative with the reason for dividing the Circuit Segment into Subprojects (using the Subproject process required by Section 2.4.2.2).

An Undergrounding Project that has completed Screen 3 can proceed to Screen 4. Undergrounding Projects that have completed Screen 3 are reported as Confirmed Projects in Progress Reports.

1) Use of Screen 3 for Individual Undergrounding Projects

PG&E uses Screen 3 to evaluate the design variations to evaluate 100 percent Underground, against the Screen 3 Alternative Mitigation and Additional Comparison 2 and, if feasible, review against Additional Comparison 3 described in Table 3-9 above. The issues that PG&E considers during the Screen 3 process are described in our typical scoping process immediately below this subsection and shown in Figures 3-4 to 3-8.

Any Circuit Segment with work in progress that was started before January 1, 2028 will be reviewed in Screen 3 and assigned a Project_ID. Projects will be either included in the Project Table (if remaining scope of work includes undergrounding) or the Non-EUP Project Table (if remaining scope of work does not include undergrounding).

The Pre-Wildfire distribution infrastructure and associated risk is used as the comparison Baseline for Fire Rebuild Projects to be evaluated as part of the EUP.[102]

2) Details of Typical Scoping Process

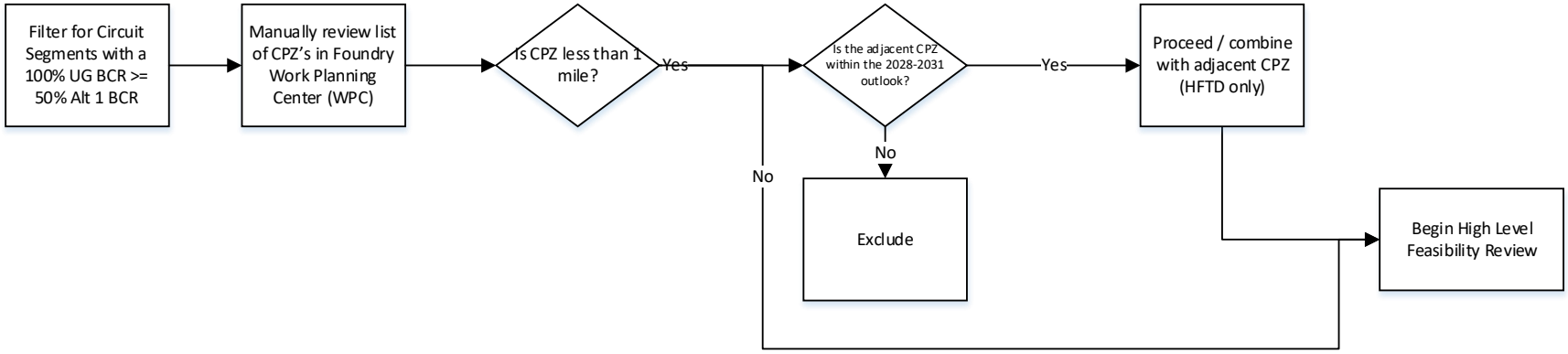
The typical scoping process consists of the following activities that are outlined in the figures below.

- Figure 3-4: Refining the Screen 2 Proposed Project List;
- Figure 3-5: High-Level Feasibility Review;
- Figure 3-6: Alternative Mitigation Review;
- Figure 3-7: Benefit-Cost Comparison;
- Figure 3-8: Additional Comparison 3 Benefit-Cost Analysis.

Following the Project selection approach outlined in the figures below, PG&E undertakes Project evaluation and documentation through the Desktop Scoping Meeting, Final Cost Analysis, and Final Design Basis Memorandum (DBM) Packaging.

[102] The risk profile of the pre-wildfire distribution infrastructure for Fire Rebuild Projects where the fire occurred before January 1, 2023 would not be available for baseline comparisons. See discussion of previously-scoped projects in Chapter 3, Section D.5.

FIGURE 3-4:
REFINING THE SCREEN 2 PROPOSED PROJECT LIST



3) Refining the Screen 2 Proposed Project List

PG&E begins the Screen 3 process by refining the Screen 2 proposed Project list.

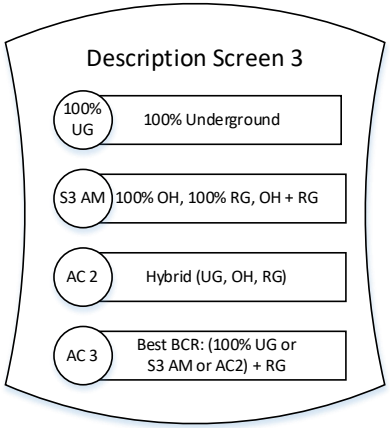
First, we identify Circuit Segments where the BCR for 100 percent Undergrounding is greater than or within 50 percent of the BCR for the Screen 2 Alternative Mitigation 1. The 50 percent assumption is implemented to support prioritization of Circuit Segments that have the highest likelihood of requiring undergrounding and ensures that the screening process does not exclude Circuit Segments that warrant consideration for undergrounding due to risk characteristics not fully captured in the BCR calculations, such as tree-strike risk, ingress/egress risk, and PSPS risk. Screen 3 calculations are based on engineering estimates developed during scoping using a project complexity assessment rather than a strict unit cost assumption. Through the Screen 3 process, PG&E can thoroughly review the risks in the Circuit Segments. The output from this refinement process is a list of Circuit Segments that are prioritized for additional review.

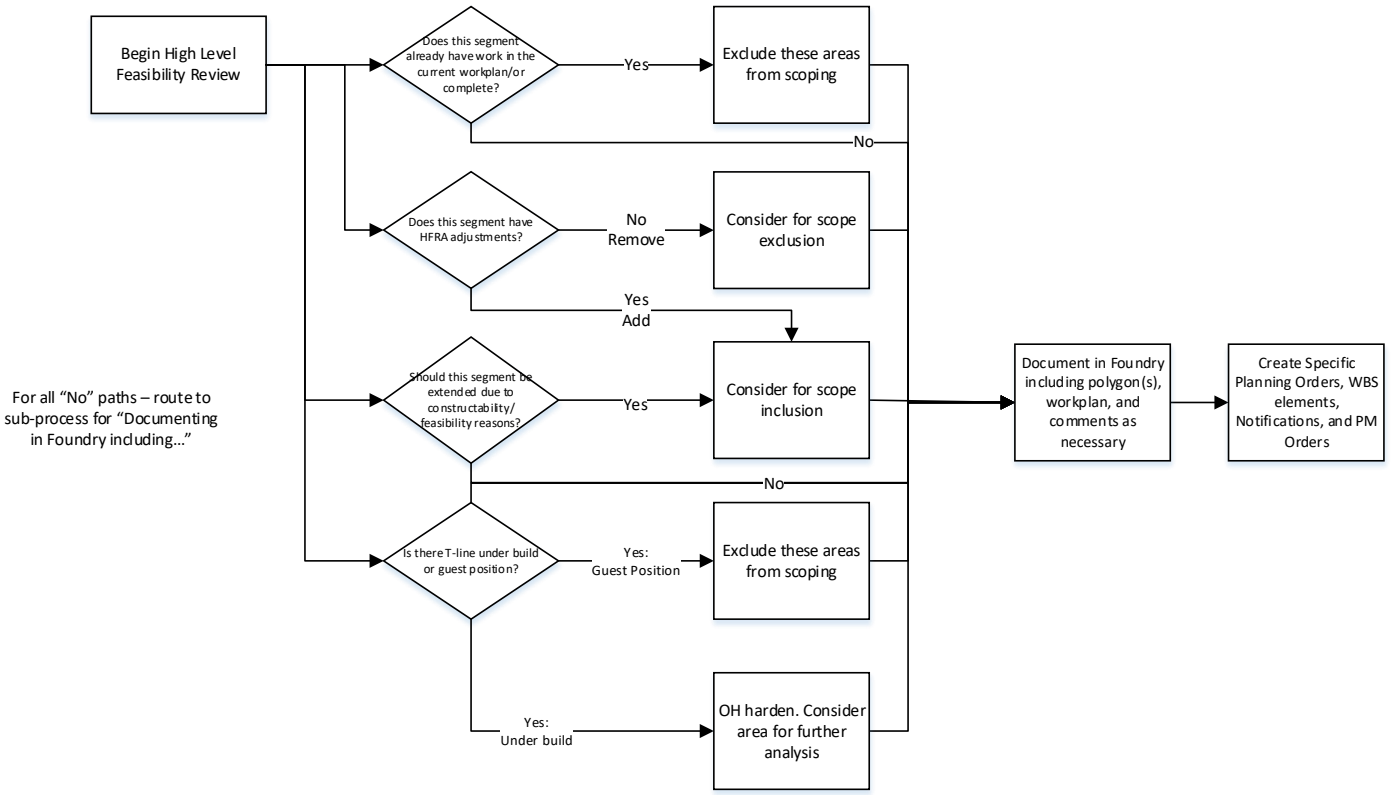
Next, PG&E identifies Circuit Segments that are less than one mile in length (Short Circuit Segments) and evaluates whether they can be combined with adjacent Circuit Segments. Short Circuit Segments may be combined with adjacent Circuit Segments that are planned for system hardening, provided those adjacent segments are expected to be included in the workplan within the next few years. If no adjacent Circuit Segments are planned for hardening, Short Circuit Segments are generally excluded from further consideration. Prior to either combining or excluding these Short Circuit Segments, PG&E conducts a review to evaluate whether the Short Circuit Segment presents meaningful wildfire risk, or whether the estimated risk is influenced by known modeling phenomena that affect comparability with other Circuit Segments. For example, a high concentration of modeled assets (e.g., switches, transformers, or insulators) within a small geographic area may result in disproportionately elevated Risk

Density that does not reflect real-world conditions. In addition, some Circuit Segments may consist only of single spans of conductor or isolated pieces of equipment, for which modeling is not intended to provide precise risk estimates and therefore warrant additional review.

After we refine the Screen 2 proposed Project list, we begin the Screen 3 High-Level Feasibility Review (Figure 3-5 below).

FIGURE 3-5:
HIGH-LEVEL FEASIBILITY REVIEW





4) High-Level Feasibility Review

For Circuit Segments that were not excluded by the Project list refinement described in Figure 3-4, PG&E conducts a High-Level Feasibility Review.

If the Circuit Segment or parts of the Circuit Segment are already included in the current Workplan or system hardening work is complete, the Circuit Segment or parts therein are excluded from consideration for undergrounding in the EUP.

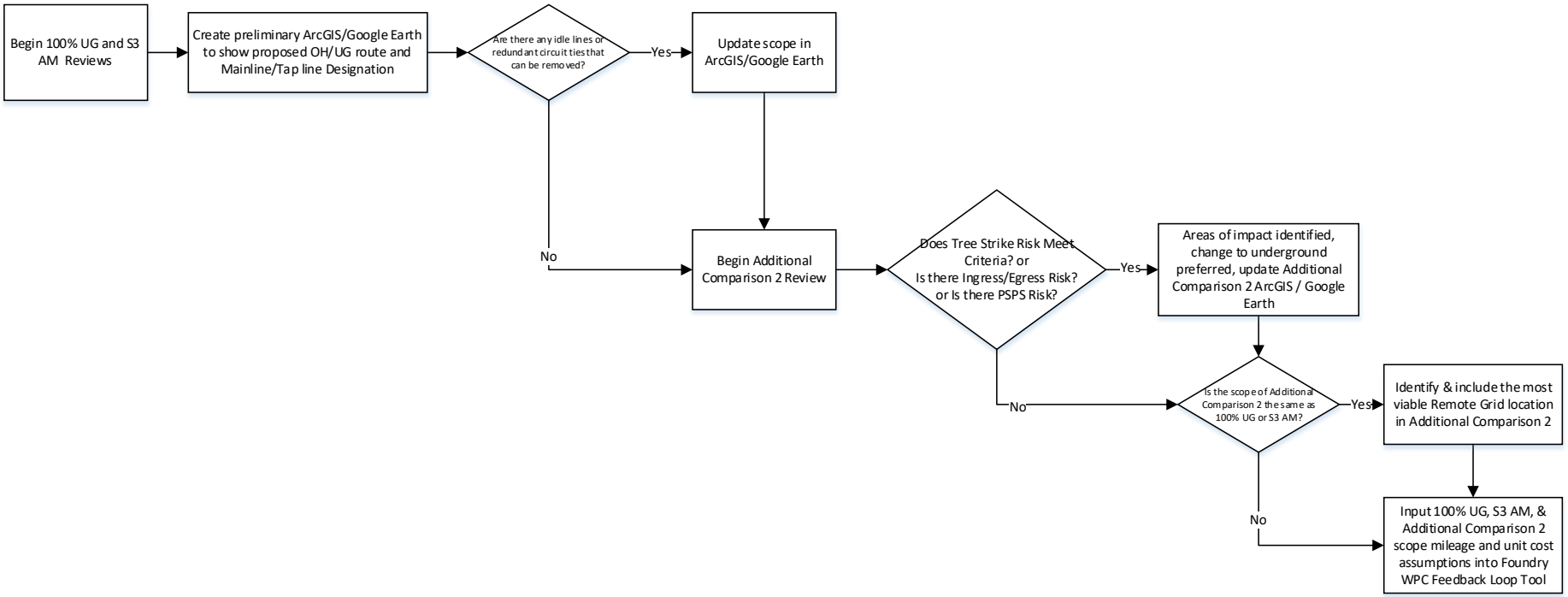
PG&E also determines if a distribution Circuit Segment is associated with a transmission line. Circuit Segments constructed under a transmission line (referred to as “T-line under-build”) are generally only considered for overhead hardening. Similarly, electric distribution lines in a transmission “guest position” (essentially built to transmission standards and sharing a structure with transmission lines but operated at a lower, distribution voltage) are excluded from consideration for overhead hardening or undergrounding in the EUP.

We also check if the Circuit Segment crosses the HFTD boundary into non-HFTD. Circuit Segment spans that cross the HFTD boundary and are up to two adjacent spans in non-HFTD may be considered for undergrounding (EUP Guidelines, Section 2.4.3.1.).

PG&E then documents the results of the high-level feasibility review and creates internal Project management and tracking documents including Planning Orders, Work Breakdown Structure (WBS) Elements, Notifications and Project Management Orders.

After completing the high-level feasibility review, PG&E conducts an Alternative Mitigation review as shown in Figure 3-6 below.

FIGURE 3-6:
ALTERNATIVE MITIGATION REVIEW



5) Screen 3 Alternative Mitigation Review

The Alternative Mitigation review starts by creating preliminary drawings in ArcGIS/Google Earth to show the proposed overhead and/or underground routes and the mainline/tap line designation. During this review, we also determine if there are any idle lines or redundant circuit ties that can be removed.

If there are idle or redundant circuit ties, then we update the scope in ArcGIS/Google Earth. If there are no idle lines or redundant circuit ties that could be removed, then we begin a review of Additional Comparison 2. This review of Additional Comparison 2 assesses the Circuit Segment and surrounding areas to determine if one or more of the following conditions exist:

- High Tree Strike Risk: In areas with high tree strike risk, undergrounding permanently eliminates exposure to vegetation contact, a leading wildfire ignition driver that cannot always be fully mitigated through overhead hardening and/or vegetation management. Our Grid Design engineers use the most recent LiDAR information available and satellite imagery to review whether the trees are tall enough to strike the lines and their potential to strike and break hardened conductors. PG&E uses six or more trees per span as the threshold for determining if tree strike potential warrants further consideration of undergrounding instead of overhead hardening.
- Ingress/Egress Concerns: Where overhead facilities traverse constrained roadways or evacuation routes, undergrounding removes the risk of lines obstructing ingress and egress during emergency conditions. Our Grid Design engineers conduct a detailed analysis of local conditions at the street level to assess ingress and egress. This granular approach allows them to identify specific ingress and egress challenges that may not be apparent in city or county-level data. For instance, they can assess the condition of specific roads, the presence of potential obstacles, and the overall accessibility of the area. This step

includes analysis by the Public Safety Specialist (PSS)[103] in the area. Input from these experts with local knowledge is important because they can add insight on community factors that allow us to determine whether undergrounding would be more effective in reducing wildfire-related risks, including risks related to ingress and egress during a wildfire.

- PSPS Event Probability: PSPS events are driven by geographically defined risk conditions that do not align with circuit boundaries. If the PSPS polygon (area where climatological conditions warrant taking PSPS) covers only part of the Circuit Segment, targeted undergrounding of only the affected portion of a Circuit Segment provides a precise, risk-based means of reducing PSPS exposure without necessarily undergrounding all parts of that Circuit Segment.

Undergrounding is the most appropriate mitigation where local conditions (i.e., presence of fall-in tree risk, ingress, and egress needs, and previous PSPS impacts) require a more effective mitigation for wildfire, reliability, and/or public safety risks than overhead hardening. If PG&E identifies one of these areas of impact, we will consider undergrounding as the preferred mitigation and consider implementing overhead hardening in those areas not impacted by these conditions and risks. Based on this review, Additional Comparison 2 would be made up of hybrid mitigations (Subprojects).

PG&E then determines if the scope of Additional Comparison 2 is the same as the scope for the 100 percent Undergrounding solution or Screen 3 Alternative Mitigation.

- If it is the same, we identify a viable location for a remote grid and create a combined mitigation alternative (with Remote Grid) to be considered as Additional Comparison 2.

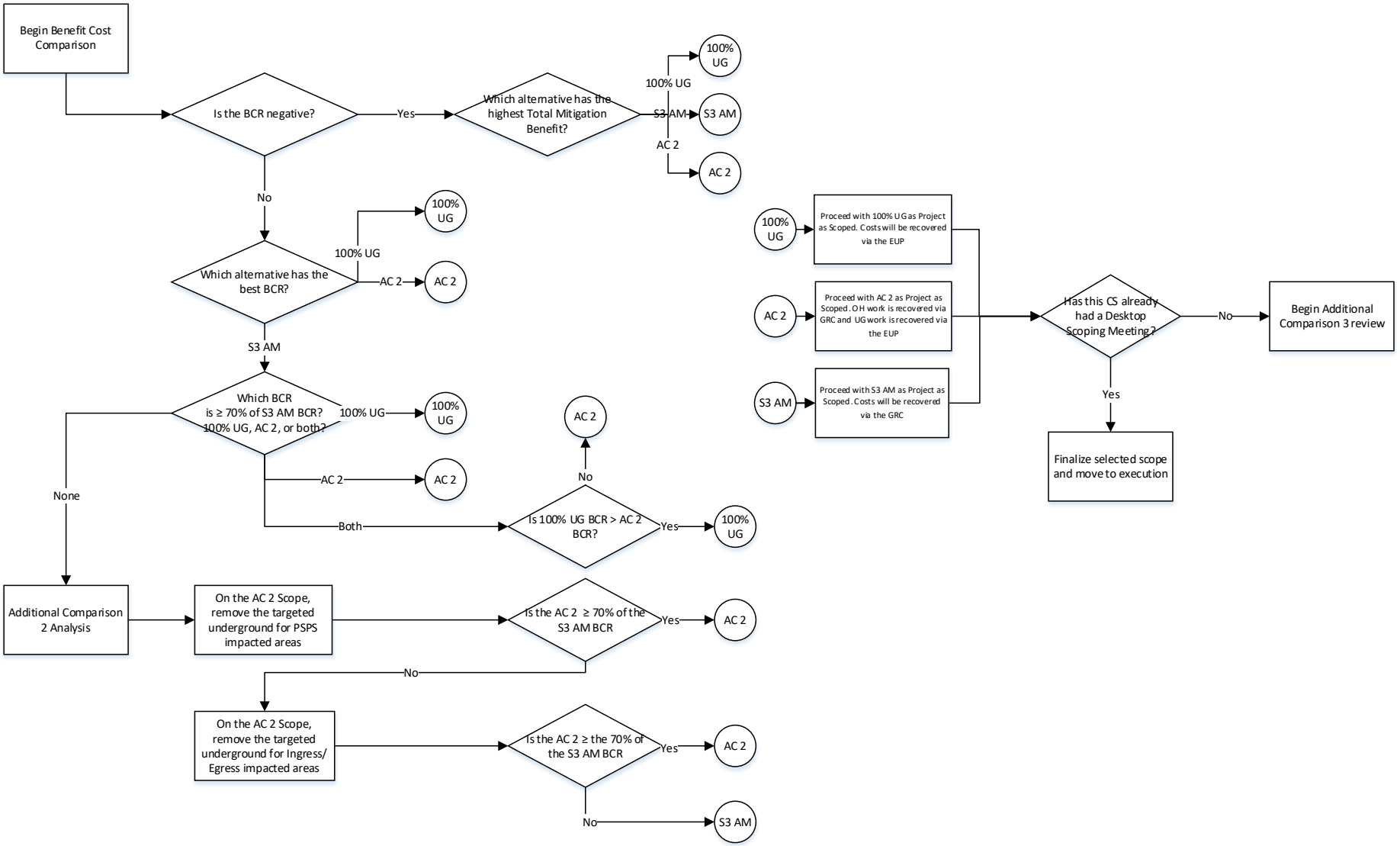
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103 This qualitative assessment is based on their collective 300+ years of fire experience. PG&E PSS team members have extensive, local wildfire operations experience. Many had a previous career with CAL FIRE or other fire agencies.

- If the scope of Additional Comparison 2 is not the same as the scope for the 100 percent Undergrounding solution or Screen 3 Alternative Mitigation, we input the 100 percent Undergrounding solution, Screen 3 Alternative Mitigation, and Additional Comparison 2 scope, unit cost assumptions and mileage into the Feedback Loop Model[104] and conduct the benefit-cost comparison and Additional Comparison 2 review shown in Figure 3-7 below.

[104] PG&E uses the Feedback Loop Model to compare and analyze different mitigations by updating the alternative scenarios with the appropriate scope and cost assumptions.

FIGURE 3-7:
BENEFIT COST COMPARISON



6) Benefit-Cost Comparison

The benefit-cost comparison determines which mitigation is appropriate on a specific Circuit Segment based on several iterations of BCR analyses.

First, PG&E determines which alternative has the best BCR (or has a negative BCR).[105] The first comparison of mitigations is summarized below and further detailed in Table 3-9:

- 100 percent Undergrounding: Proceed with 100 percent Undergrounding in the EUP.
- Screen 3 Alternative Mitigation: Conduct additional analysis to identify if localized risk factors are present.
- Additional Comparison 2: Proceed with Project as Scoped. The undergrounding work is included in the EUP and overhead hardening and/or remote grid is addressed in the GRC.

PG&E reviews BCRs for comparison of each Alternative Mitigation and Additional Comparison (100 percent Undergrounding, Screen 3 Alternative Mitigation and Additional Comparison 2), if 100 percent Undergrounding or Additional Comparison 2 have a BCR that is at least 70 percent of Screen 3 Alternative Mitigation. The 70 percent assessment reflects an estimate uncertainty range applied to BCR results to account for known limitations and uncertainties in cost estimates and risk model outputs at the Project-selection stage. Specifically, PG&E applies a 30 percent estimate uncertainty range in the EUP application, which means that a more risk reducing mitigation alternative (e.g., undergrounding) may be considered when it has an estimated BCR that is at least 70 percent of the BCR for Screen 3 Alternative Mitigation. The 70 percent framing is simply 100 percent minus the 30 percent uncertainty range and does not represent a separate or additional threshold. This estimate uncertainty range is based on:

[105] A BCR may be negative where the investment returns a net positive cashflow such that the "cost" is negative, making it a good economic investment even without consideration of the risk reduction related benefits.

- Industry-standard estimating practice (~~ACEE~~Association for the Advancement of Cost Engineering Cost Estimate Classifications), which recognizes that cost estimates developed during Project scoping are not yet fully mature;
- Energy Safety's recommendation in its decision on PG&E's 2026-2028 Base WMP to reduce the prior 50 percent estimate uncertainty range to 30 percent, reflecting improvements in data quality and modeling while still accounting for residual existing uncertainty in the decision-making process;[106] and
- Inherent uncertainty in modeled risk point estimates, driven by compounding assumptions, variability in inputs, and structural limitations of quantitative risk models.

Where the BCR results fall within this uncertainty range, PG&E evaluates site-specific factors that are not fully captured in quantitative models, namely the factors described in Section D.3.a.5 above: ingress and egress constraints, tree-strike exposure, and PSPS risk, to determine whether a more risk-reducing alternative is more prudent than overhead hardening.

The estimate uncertainty range therefore provides appropriate flexibility to select the safer, more risk-reducing option when modeled BCRs are close and known uncertainty exists. Below is a numerical example of how the 70 percent factor will be applied, in this example:

- 100 percent Undergrounding
- Screen 3 Alternative Mitigation
- Additional Comparison 2

We consider the 100 percent Undergrounding or an Additional Comparison alternative when the BCR is at least 70 percent of the BCR for the Screen 3 Alternative Mitigation, as shown below:

[106] Office of Energy Infrastructure Safety's (OEIS) Decision for the PG&E 2026-2028 Base Wildfire Mitigation Plan (Feb, 5, 2026), pp. 19-20.

Formula: (70%) * BCR_S3_AM ≤ BCR_x

Where BCR_x represents the BCR of either 100 percent Underground or Additional Comparison 2.

Using the example data in Table 3-10 below, the application of the 70 percent threshold is calculated in the below formula:

Formula: (70%) * 7.50 = 5.25

TABLE 3-10:
EXAMPLE OF 70 PERCENT THRESHOLD APPLICATION

Line No.	Category	100% UG	S3 AM	Additional Comparison 2
1	Benefits	$25	$15	$21
2	Costs	$4	$2	$3
3	BCR	6.25	7.5	7.0

BCRs for both 100 percent Undergrounding (6.25), and Additional Comparison 2 (7.0) are greater than Screen 3 Alternative Mitigation (5.25), so a more cost-effective alternative than overhead hardening may be selected. The BCR for Additional Comparison 2 is greater than the BCR for 100 percent Undergrounding, therefore, Additional Comparison 2 (Hybrid) would be selected in this case contingent on local conditions supporting the need for the greater risk mitigating alternative.

a) BCR Comparisons

If Screen 3 Alternative Mitigation has the best BCR, PG&E determines if the BCR for 100 percent Undergrounding or Additional Comparison 2 is greater than or equal to 70 percent of the BCR for the Screen 3 Alternative Mitigation.

- If the BCR for 100 percent Undergrounding is the only alternative ≥ 70 percent of the Screen 3 Alternative Mitigation BCR: Proceed with 100 percent Undergrounding in the EUP.

- If the BCR for Additional Comparison 2 is the only alternative ≥ 70 percent of the Screen 3 Alternative Mitigation BCR: Proceed with Additional Comparison 2.
- If the BCR for both the undergrounding solution and Additional Comparison 2 are ≥ 70 percent of the Screen 3 Alternative Mitigation BCR: proceed with the alternative with the highest BCR between 100 percent Undergrounding and Additional Comparison 2.
- If neither the BCR for 100 percent Undergrounding nor the BCR for Additional Comparison 2 are ≥ 70 percent of the Screen 3 Alternative Mitigation BCR: Conduct Additional Comparison 2 analysis, as described in the paragraphs below.

If Screen 3 Alternative Mitigation is still the best BCR and no other mitigation is within 30 percent (i.e., ≥ 70 percent), PG&E conducts an Additional Comparison 2 analysis, essentially creating a revised Additional Comparison 2 Project scope, as described below.

First, we exclude targeted undergrounding for PSPS impacted areas (allowing for overhead hardening in those areas) from the current Project scope and determine if the BCR for this revised Additional Comparison 2 is greater than or equal to 70 percent of the BCR for Screen 3 Alternative Mitigation.

If the BCR for Additional Comparison 2 is greater than or equal to 70 percent of the BCR for Screen 3 Alternative Mitigation, we proceed with this revised Additional Comparison 2.

- If the BCR for this revised Additional Comparison 2 is still less than 70 percent of the BCR for Screen 3 Alternative Mitigation, we exclude targeted undergrounding for ingress/egress impacted areas (allowing for overhead hardening in those areas) from the current Project scope. We then test if the BCR for Additional Comparison 2 is

greater than or equal to 70 percent of the Screen 3 Alternative Mitigation BCR.

If the BCR for Additional Comparison 2 is greater than or equal to 70 percent of the Screen 3 Alternative Mitigation BCR, proceed with Additional Comparison 2. If the BCR for Additional Comparison 2 is less than or equal to 70 percent of Screen 3 Alternative Mitigation BCR, proceed with Screen 3 Alternative Mitigation. PG&E then conducts the Additional Comparison 3 review shown in Figure 3-8 below and described below.

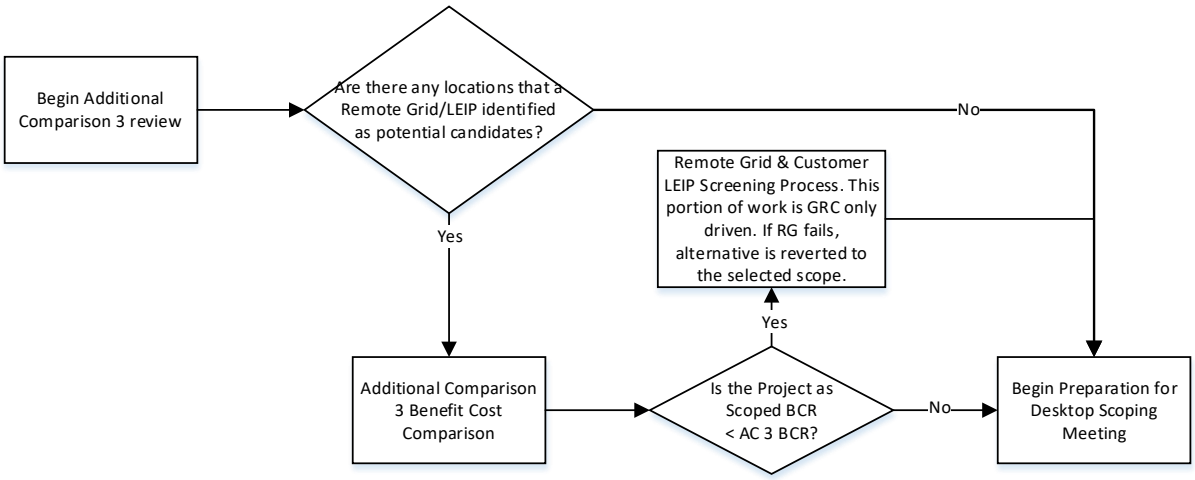
b) BCR Calculations

Occasionally, BCR calculations may result in a negative number. There are two instances where this happens:

1) When the O&M cost savings of the selected mitigation (PV over the life of the asset) exceeds the capital installation costs of the Project (i.e., the BCR calculation would have a negative denominator). Such outcomes represent economically favorable mitigations, as they effectively have no cost, and are therefore treated as exceeding the BCR ≥ 1.0 threshold for EUP eligibility.
2) When the mitigation alternative introduces a net new risk (e.g., EPSS risk) to the system that outweighs the wildfire risk reduction. Such outcomes represent economically unfavorable mitigations, as the risk introduced to the system exceeds the potential benefits (i.e., the BCR calculation would have a negative numerator).

PG&E may select alternatives with a negative BCR when the negative BCR is driven by the difference in the net O&M costs and capital installation costs. PG&E will not select a mitigation where, as described in the second example above, the mitigation would create a new net risk.

FIGURE 3-8:
ADDITIONAL COMPARISON 3 BENEFIT COST ANALYSIS



7) Additional Comparison 3 Benefit-Cost Analysis

The Additional Comparison 3 benefit-cost analysis consists of further evaluating portions of Circuit Segments to determine if they are candidates for the Remote Grid and/or the Line Elimination Incentive Program (LEIP). Segments are considered for Remote Grid and LEIP if they are end of line (or will be end of line after system hardening mitigations are applied) and are relatively long and serve only a small number of customers. Each Circuit Segment that is being evaluated in Screen 3 goes through an Additional Comparison 3 analysis. This step is essential to evaluate the Remote Grid or LEIP alternative as this mitigation typically impacts only a small portion of the Project.

If there are candidates for Remote Grid or LEIP in the Circuit Segment, PG&E completes a desktop screening process to identify any site-specific features that would render Remote Grid or LEIP infeasible and generate an expected cost for Remote Grid and/or LEIP. If it is determined through this initial screening process that Remote Grid is potentially feasible for the location(s), an additional BCR calculation is completed for Additional Comparison 3. Additional Comparison 3 would take the selected alternative from the previous steps (100 percent Undergrounding, Screen 3 Alternative Mitigation, or Additional Comparison 2) and then

combine it with Remote Grid or LEIP in the confirmed portion of the Project. We then test if this BCR for this new Additional Comparison 3 is greater than the Project as Scoped BCR, which results from the comparison of 100 percent Undergrounding, Screen 3 Alternative Mitigation and Additional Comparison 2.

- If the BCR for Additional Comparison 3 is greater than the Project as Scoped BCR derived from the previous analysis, Additional Comparison 3 becomes the new Project as Scoped.
- If the BCR for Additional Comparison 3 is less than the Project as Scoped BCR, we do not proceed with Additional Comparison 3.

If there are no opportunities for Remote Grid or LEIP, PG&E proceeds to the desktop scoping meeting with the preferred alternative mitigation based on the BCR results.

8) Desktop Scoping Meeting, Final Cost Analysis, Final DBM Packaging

Once a preferred mitigation alternative has been identified, PG&E prepares for a desktop scoping meeting. Prior to the meeting, PG&E develops preliminary sketches, analyzes fire risk, vegetation, and engineering requirements; identifies constructability limitations; and completes necessary field visits. This information is reviewed during the desktop scoping meeting.

Following the meeting, we update the proposed system hardening route with a digital map file (a KMZ) and, for Hybrid Projects, recommend segmentation into Subprojects. PG&E then begins the final cost analysis and inputs updated scope and cost information into the feedback loop calculations. We rerun the BCR analysis with the updated mileages and unit costs, and we repeat the BCR comparison described above for all alternatives as it is possible that there are changes identified during the desktop scoping meeting that could impact the final decision of which Alternative Mitigation will be selected as the Project as Scoped. Once PG&E identifies the preferred mitigation configuration through the Screen 3 process, including consideration of both BCR results

and site-specific factors, BCR evaluation is complete and the scope of the selected project advances through the remainder of the Project Acceptance Framework.

The DBM documents the preliminary design and identifies important information about the Project and documents key engineering considerations and records decisions made. PG&E then creates specific planning orders, reviews Subproject segmentation, scope, and schedule, and updates key sketches and work descriptions. To complete scoping, we route the DBM for approval and attach a scope document to each order in SAP, our system of record.

The detailed scoping process is shown in the end-to-end Project Acceptance Framework diagram.[107] For each Undergrounding Project with Subprojects, we list in Table C.14 to the Progress Report 0 the mitigation for each Subproject and a narrative with the reason for dividing the Circuit Segment into Subprojects (using the Subproject process required by EUP Guidelines Section 2.4.2.2).

9) Screen 3 Procedure for Selecting Alternative Mitigations Consistent With Section 2.7.10

In Section D.3.a.1-8, above, PG&E describes our procedure for selecting Alternative Mitigations and Additional Comparisons consistent with EUP Guidelines Section 2.7.10. The EUP Guidelines require us to consider the Wildfire Risk reduction and reliability improvement elements of the Plan Mitigation Objective of an Undergrounding Project and include comparing risk metrics for 100 percent Undergrounding, Alternative Mitigations and Additional Comparisons. We also describe how we compare undergrounding to other Alternative Mitigations and Additional Comparisons and use the outcome of these comparisons to select the appropriate mitigation for each Circuit Segment.

[107] See Attach. B, WP003 (Project Prioritization and Decision Tree).

10) Incorporating Project Specific Information Into the Selection of Alternative Mitigations

PG&E incorporates specific cost and scope information into our selection of Alternative Mitigations and Additional Comparisons through the scoping process described in Section D.3.a.1-8. During scoping, we run different project variations through the Feedback Loop and evaluate the BCR for the different project variations. After the desktop scoping meeting, the final mitigation analysis includes a review of the BCR using the proposed mileage and cost assumptions. The final benefit-cost analysis incorporates Project-specific cost and scope information gathered through the scoping process and confirms our final mitigation selection.

11) Determining Baseline Values

PG&E establishes Baselines using the WDRM v4 asset configuration, which is anchored to a January 1, 2023 grid snapshot.[108] Baseline values used for forward-looking evaluation are subsequently calibrated through postprocessing adjustments to reflect expected 2028 conditions, including recognition of historical hardening completed since the snapshot date and application of appropriate climate escalation factors.

The Baseline scenario is a foundational element of the BCR calculation because it establishes the reference condition against which all costs and benefits are measured. Its purpose is to enable a consistent assessment of the incremental impacts of each of the proposed mitigations. As directed by Energy Safety in EUP Guidelines Section 2.7.10, PG&E will use a Baseline consisting of bare overhead wire paired with PSPS, EPSS and DCD capability.

Core Capability 6 requires PG&E to describe how we establish and maintain Baselines and historical model calibrations used to evaluate system risk and compare Undergrounding Projects, Alternative Mitigations, and Additional Comparisons. In subsequent

[108] This snapshot is based on the WDRM v4 process for establishing a risk Baseline for the purposes of the WDRM v4. See Chapter 7 Section C for further detail.

annual Baseline updates, PG&E will account for changes in system conditions and risk reduction, as described in Chapter 7, Section G.6 Core Capability 6.

12) Determining Which Portions of a Circuit Segment Will Be Undergrounded With the Scoping Process

In Section D.3.a.1-8 above, PG&E describes how we determine which portions of a Circuit Segment will be undergrounded.

b. Twenty-Five Undergrounding Project Requirement (EUP Guidelines Section 2.4.5.2)

The filed EUP must include a Portfolio of at least 25 individual Undergrounding Projects considered under Screen 3. This Portfolio must include:

a. at least one Circuit with multiple Undergrounding Projects.

b. at least three Undergrounding Projects with multiple Subprojects (if Subprojects will be part of the EUP).

c. at least three Undergrounding Projects with non-undergrounding Subprojects (if non-undergrounding Subprojects will be part of the EUP).

d. at least two Undergrounding Projects considered for the High Frequency Outage Program Threshold (if High Frequency Outage Program will be part of the EUP).

e. at least two Undergrounding Projects considered for the Ignition Tail Risk Threshold (if Ignition Tail Risk will be part of the EUP).

Additionally, the Large Electrical Corporation must present, in a separate section, an analysis of at least one Undergrounding Project which the Large Electrical Corporation does not plan on undergrounding due to factors that are captured in the Screen 2 and Screen 3 analysis. This analysis must be presented with narrative description and associated numerical tables in Progress Report 0, named "Example Rejected Project(s)."

1) Introduction to Portfolio 0 and Validation Against Required Portfolio Criteria

Our first Portfolio of 28 Projects (Portfolio 0) is summarized below in Table 3-11.

TABLE 3-11:
SUMMARY OF PROJECTS INCLUDED IN PORTFOLIO 0

Line No.	Circuit ID1	Circuit Segment ID1	Proj. ID[a]	Length (Miles)[a]	County[a]	OUR[b]	BCR – Project as Scoped[c]
1	PUEBLO 2103	PUEBLO 21031970	Proj00001	3.1	Napa	$3.6	(15.6)[d]
2	MIWUK 1701	MIWUK 1701CB	Proj00002	4.6	Tuolumne	$1.9	8.6
3	FORESTHILL 1101	FORESTHILL 1101CB	Proj00003	9.0	Placer	$4.9	7.0
4	DUNBAR 1103	DUNBAR 1103799422	Proj00004	0.4	Sonoma	$0.1	6.1
5	FORESTHILL 1101	FORESTHILL 11011820	Proj00005	5.7	Placer	$0.4	(6.5)
6	GIRVAN 1101	GIRVAN 1101CB	Proj00006	1.2	Shasta	$1.2	13.4
7	LOS GATOS 1107	LOS GATOS 1107812664	Proj00007	8.2	Santa Clara	$1.1	2.7
8	GEYSERVILLE 1102	GEYSERVILLE 1102904170	Proj00008	21.2	Sonoma	$4.4	1.8
9	ALTO 1124	ALTO 1124430	Proj00009	7.1	Marin	$1.7	4.4
10	LAURELES 1112	LAURELES 111268454	Proj00010	7.8	Monterey	$1.5	2.8
11	EL DORADO PH 2101	EL DORADO PH 2101668674	Proj00011	9.4	El Dorado	$6.4	20.8
12	JESSUP 1101	JESSUP 110168362	Proj00012	4.9	Shasta	$2.0	4.3
13	BEN LOMOND 0401	BEN LOMOND 0401944178	Proj00013	7.7	Santa Cruz	$2.3	3.4
14	WOODACRE 1102	WOODACRE 1102851	Proj00014	1.3	Marin	$0.4	11.3
15	ELECTRA 1101	ELECTRA 1101CB	Proj00015	23.3	Amador	$5.6	3.0
16	MARIPOSA 2101	MARIPOSA 210110070	Proj00016	25.7	Mariposa	$2.2	2.3
17	SAN RAFAEL 1108	SAN RAFAEL 1108322	Proj00017	7.3	Marin	$3.3	9.1
18	OAKLAND X 1104	OAKLAND X 1104CR288	Proj00018	2.7	Alameda	$1.6	11.9
19	WOODACRE 1102	WOODACRE 1102137662	Proj00019	8.5	Marin	$2.5	3.3
20	CAMP EVERS 2105	CAMP EVERS 210510294	Proj00020	4.9	Santa Cruz	$0.3	4.7
21	STILLWATER 1102	STILLWATER 11021466	Proj00021	20.1	Shasta	$2.1	2.9
22	KONOCTI 1102	KONOCTI 1102714370	Proj00022	2.4	Lake	$0.3	3.2
23	PLACERVILLE 2106	PLACERVILLE 21069712	Proj00023	24.7	El Dorado	$6.0	3.9
24	MENLO 1102	MENLO 1102628458	Proj00024	1.1	San Mateo	$0.1	(42.1)
25	ALTO 1122	ALTO 11221260	Proj00025	2.8	Marin	$0.3	2.6
26	CAMP EVERS 2105	CAMP EVERS 2105534190	Proj00026	3.4	Santa Cruz	$0.1	21.0
27	CORTINA 1101	CORTINA 1101302192	Proj00027	1.3	Colusa	$3.1	1,653.1
28	VOLTA 1102	VOLTA 1102CB	Proj00028	3.3	Shasta	$2.5	60.3

(a) Derived from multiple tables. First table is in Table C.6 Circuit Segment Identification Table.

(b) Derived from Table C.8 Circuit Segment Risk Score Table.

(c) Derived from Table C.15 Project Index Table.

(d) The reason a BCR may be negative but produce substantial customer benefits is discussed in Section D.3.a.6).

Table 3-12 below shows that Portfolio 0 includes Projects that meet the EUP Guidelines' requirements for the first 25 Projects. More information about these 28 Projects is included in Progress Report 0 Tables C.12, C.13, C.14, and C.15.

TABLE 3-12:
EUP REQUIREMENTS FOR PROJECTS INCLUDED IN PORTFOLIO 0

Line No.	Project Type	Required Number of Projects[(a)]	Number of Projects in Portfolio 0
1	Circuits with Multiple Undergrounding Projects	1	6
2	Undergrounding Projects with Multiple Subprojects	3	12[(b)]
3	Undergrounding Projects with Non-Undergrounding Subprojects	3	12
4	Undergrounding Projects Considered for High-Frequency Outage Program Threshold	2	2
5	Undergrounding Projects Considered for Ignition Tail Risk	2	2

(a) Note there is overlap in the Projects that meet the requirements (i.e., Projects can meet multiple requirements).

(b) PG&E's process to identify Subprojects based on the mitigation type will lead to zero Projects in the Portfolio with multiple Undergrounding Subprojects.

2) Example of a Rejected Undergrounding Project Due to Factors Captured in Screens 2 and 3

The following is an example of a rejected Project that did not meet the BCR requirements and was not feasible for construction.

PG&E evaluated a Circuit Segment in Santa Ynez as part of our EUP Project Acceptance Framework analysis and determined that we would not pursue undergrounding due to factors captured in Screen 3 as discussed below.

- Screen 1: The Santa Ynez Circuit Segment is in an HFTD and meets the High-Risk Threshold. It was therefore considered EUP eligible and passed Screen 1.
- Screen 2: PG&E had sufficient information to calculate a BCR for three alternatives and therefore the Circuit Segment passed

Screen 2. There is sufficient information as this Circuit Segment had bare overhead conductor in the HFTD.

- Screen 3: PG&E compared the BCRs for the three mitigations and saw that Screen 3 Alternative Mitigation had the highest BCR and that neither 100 percent Underground nor Additional Comparison 2 were within the estimate accuracy range of the BCR for Screen 3 Alternative Mitigation. There were no Remote Grid / LEIP sites identified as part of Additional Comparison 3.

TABLE 3-13:
BCR COMPARISON OF EXAMPLE REJECTED PROJECT

Line No.	Alternatives Evaluated	BCR
1	100% UG	4.035
2	Screen 3 Alternative Mitigation	18.375
3	Additional Comparison 2	11.293

PG&E conducted a constructability evaluation and area of impact analysis to determine if there was significant tree strike risk, ingress/egress risk or PSPS risk that would warrant further consideration of undergrounding as the appropriate mitigation solution. During these additional evaluations, PG&E determined that undergrounding is infeasible in this location because:

1) There is only one small section of tree strike risk along the entire proposed route;
2) The Circuit Segment is in a rural area and there is no significant PSPS risk or ingress/egress risk; and
3) A portion of the proposed undergrounding route is along a walking trail that is unsuitable for vehicular traffic and would require building a new road.

Given the favorable BCR for Screen 3 Alternative Mitigation (driven in part by the significant constructability issues for undergrounding), and lack of significant tree strike, ingress/egress or PSPS risks, PG&E selected overhead hardening as the appropriate mitigation.

4. Screen 4: Project Prioritization and Finalization (EUP Guidelines Section 2.4.6)

Pursuant to section 8388.5(c)(2), the EUP must include a means of prioritizing Undergrounding Projects based on "wildfire risk reduction, public safety, cost efficiency, and reliability benefits."

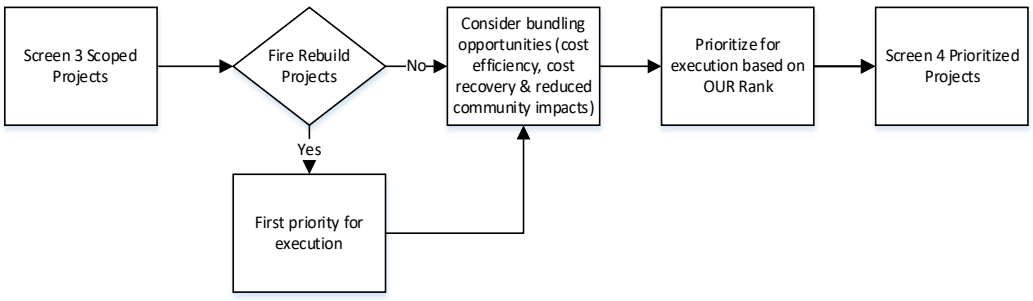
For Screen 4 (Project Prioritization and Finalization), the EUP must set forth a means of prioritization and its definition for each of the factors in Section 8388.5(c)(2), i.e., wildfire risk reduction, public safety, cost efficiency, and reliability benefits. If an Undergrounding Project is divided into Subprojects, the Large Electrical Corporation must consider the different completion times of Subprojects and the effect of staggered completion times, consistent with the timeline requirements in Section 2.7.5, Core Capabilities 4 and 5. Additionally, the costs, benefits, and CPUC CBR are calculated for the design variations that were used in Screen 3, including the "Screen 3 Alternative Mitigations," the "Project as Scoped," and the "Undergrounding as Scoped." Appendix C.1.13, Screen 4 Table, gives instructions for the type of information required in Screen 4.2.

In the context of this project prioritization, the Large Electrical Corporation may define reliability benefits to include benefits not related to Outage Program Events. The EUP must describe how the factors will be applied to set priority for Confirmed Projects. The EUP must describe how the prioritization aligns with and supports the Plan Mitigation Objective. The EUP must include a narrative of the Large Electrical Corporation's rationale and supporting data (e.g., KDMMs) for each definition and the means of prioritization included in Screen 4.

The EUP must include a list of Confirmed Projects with the Screen 4 prioritization applied.

In Figure 3-9 below, PG&E describes our Screen 4 prioritization process, which establishes and supports a means of prioritizing Undergrounding Projects based on wildfire risk reduction, public safety, Cost Efficiency, and reliability benefits.

FIGURE 3-9:
SCREEN 4 PROJECT PRIORITIZATION



a. Means of Prioritization for Confirmed Projects and Definition of Each Factor in Section 8388.5(c)(2).

For context, PG&E generally treats Screen 4 prioritization as a single occurrence applied to each Project upon completion of Screen 3 but may revise initial Project priority designations under specific conditions discussed in more detail below. Therefore, Project priority designations may be revised after the identified "passed_date" in the Screen History Table. Screen 4 prioritization does not necessarily determine Project construction schedules. While Project construction schedules may inherently be informed by Screen 4 prioritization, actual timelines are primarily influenced by operational constraints such as permitting requirements and acquiring the necessary land rights for the Project.

Screen 4 considers the following factors for Project prioritization:

- Monetized Overall Utility Risk reduced per primary overhead mile removed of the Project;
- Whether the Project is a Fire Rebuild Project;
- Bundling opportunities for Cost Efficiency and/or community impact reduction; and
- Cost recovery requirements.

The Screen 4 priority output is provided in the "project_priority" data field of the Screen 4 (Table C.13) and will be provided in a format that allows alpha-numeric sorting starting with the highest-priority Projects and moving to lower priority Projects.

PG&E will primarily prioritize Projects in Screen 4 based on monetized Overall Utility Risk reduced per primary overhead mile removed. This Overall Utility Risk prioritization will be represented in the "project_priority" field nomenclature of the Screen 4 Table with a classifier "C" followed by an integer representing the relative ranking of the Project's Overall Utility Risk reduced per primary overhead mile removed. PG&E may deviate from Overall Utility Risk based prioritization under the following conditions:

- Condition 1: If the Project is a Fire Rebuild Project, then the Project will be given highest priority to support our customers by restoring

service. In this case, the priority output will be represented in the "project_priority" field nomenclature of the Screen 4 Table with a classifier "A" followed by an integer representing the relative ranking of the Project's Overall Utility Risk reduced per primary overhead mile removed. Not all Circuit Segments in a Fire Rebuild Area will be Fire Rebuild Projects, but all Fire Rebuild Projects must necessarily be in a Fire Rebuild Area.

- Condition 2: If there are opportunities to reduce costs by bundling Projects that are located near each other and/or to reduce community impacts from too much work occurring in a single community, PG&E may reprioritize and reclassify Projects in Screen 4. In these conditions, the priority output will be represented in the "project_priority" field nomenclature of the Screen 4 Table with a classifier "B" if the Project needs to be accelerated or a classifier "D" if the Project needs to be decelerated. Either classifier will be followed by an integer representing the relative ranking of the Project's Overall Utility Risk reduced per primary overhead mile removed.
- Condition 3: If cost recovery requirements established in the CPUC Phase 1 Joint Utility Application Proceeding and CPUC Phase 2 Decision[109] require Portfolio reprioritization, PG&E may reprioritize and reclassify certain Projects. PG&E will be required to establish annual cost caps with the CPUC as part of the Phase 2 cost recovery application process.[110] PG&E will manage our Portfolio to stay within the annual cost cap, which may require prioritizing certain Projects based on their estimated cost. In these conditions, the priority output will be represented in the "project_priority" field nomenclature of the Screen 4 Table with a classifier "B" if the Project needs to be accelerated or a classifier "D" if the Project needs to be decelerated. Either classifier will be followed by an

[109] Resolution SPD-37 (Dec. 10, 2025), Attachment A, p. 14, Conditions for Approval of Plan Costs, Nos. 1, 3 and 4.

[110] Resolution SPD-37 (Dec. 10, 2025), Attachment A, p. 14, Conditions for Approval of Plan Costs, No. 1.

integer representing the relative ranking of the Project's Overall Utility Risk reduced per primary overhead mile removed.

b. Rationale and Supporting Data (e.g., KDMMs) for Each Definition and Means of Prioritization

In Table 3-14 below, we summarize the factors considered in Screen 4, the rules for prioritization, the supporting data used to represent the associated Screen 4 factor, the rationale for using the Screen 4 factor, whether or not the Screen 4 factor is required by Section 8388.5(c)(2), and PG&E's definition of each factor.

TABLE 3-14:
SCREEN 4 PROJECT PRIORITIZATION FACTOR ALIGNMENT WITH SB 884

Line No.	Screen 4 Factors	Rules for Prioritization	Data	Rationale	Pub. Util. Code § 8388.5(c) (2) Req. Alignment	PG&E Definition
1	Monetized OUR reduced per primary overhead mile removed of the Project	Baseline – defaults to monetized OUR reduced per primary overhead mile removed of the Project Prioritize by highest to lowest monetized OUR reduced per primary overhead mile removed of the Project Unless overridden by Fire Rebuild, Cost Efficiency/Community Impact, or Cost Recovery Classifiers	Monetized OUR reduced per primary overhead mile removed Baseline Classifier = "C" (This will sort anything that does not fall into classifier A, B, or D)	OUR inherently considers all the factors required by Section 8388.5(c)(2) except for Cost Efficiency. That is, wildfire risk reduction and reliability benefits, which are referred to as Outage Program risk in the OUR, are the two components of OUR. Additionally, public safety is also embedded within the safety component of the Wildfire Risk and Outage Program Risk of the OUR.	Wildfire Risk Reduction	Reduction in Ignition Risk in the HFTD by implementing various mitigations including system hardening
2					Reliability Benefits	Reduction in Outage Program risk by implementing various mitigations including system hardening.
3					Public Safety	Activities that reduce risk to our communities from PG&E assets.
4	Whether the Project is a Fire Rebuild Project	Highest priority is given to Fire Rebuild Projects	Fire Rebuild Classifier = A	Fire Rebuild Projects represent, post-event safety work in areas with demonstrated wildfire risk, and are explicitly elevated in the Screen 4 framework to ensure timely service restoration and reconstruction to current fire-safe standards	Reliability Benefits	"Fire Rebuild Area" means a location where distribution infrastructure has been damaged by wildfire that is specifically identified by the Large Electrical Corporation in the EUP or in a Progress Report

TABLE 3-14
SCREEN 4 PROJECT PRIORITIZATION FACTOR ALIGNMENT WITH SB 884
(CONTINUED)

Line No.	Screen 4 Factors	Rules for Prioritization	Data	Rationale	Pub. Util. Code § 8388.5(c) (2) Req. Alignment	PG&E's Definition
5	Bundling opportunities for Cost Efficiency and/or community impact reduction	Enabling added flexibility in planning to facilitate work bundling for Cost Efficiency, commercial contracting cost savings, and/or community impact reduction	Cost Efficiency/ Community Impact Classifier = "B" if the Project needs to be accelerated or "D" if the Project needs to be decelerated	Required per SB 884	Cost Efficiency	Total cost reduction without reduction in scope of work
6	Cost recovery requirement established in the CPUC Phase 2 Decision	Enabling added flexibility in planning to facilitate meeting cost recovery requirements established in the CPUC Phase 2 Decision	Cost Recovery Classifier = "B" if the Project needs to be accelerated or "D" if the Project needs to be decelerated	PG&E will be required to establish annual cost caps with the CPUC as part of the EUP Phase 2 cost recovery Application process.	N/A	Cost recovery metrics established in the CPUC Phase 2 Decision

c. How Prioritization Supports the Plan Mitigation Objective

The Plan Mitigation Objective is the total amount of change in wildfire and reliability risk that is necessary to demonstrate that PG&E has substantially increased electrical reliability and substantially reduced the risk of wildfire through our EUP. PG&E's Plan Mitigation Objective is defined as the monetized average Overall Utility Risk reduced per primary overhead mile removed. PG&E's Screen 4 prioritization aligns with and supports the Plan Mitigation Objective because we are primarily identifying and prioritizing work on Circuit Segments with the highest monetized Overall Utility Risk reduced per primary overhead mile removed.

d. Consideration of Completion Time of Subprojects and the Effect of Staggered Completion Timeline Requirements Consistent With EUP Guidelines Section 2.7.5, Core Capabilities 4 and 5

Core Capability 4 requires PG&E to describe how we use estimated Project timelines to model the reduction of risk and increase in reliability over time.

Core Capability 5 requires PG&E to describe how we evaluate Ignition Risk and Outage Program Risk for Undergrounding Projects that are completed in stages or have multiple mitigations on a single Circuit Segment.

Undergrounding and Hybrid Projects that pass Screen 4 are already initially prioritized for Ignition Risk, Reliability Risk, Cost Efficiency, and Public Safety (as described above). At the time Screen 4 is applied to a Project, the degree to which there will be staggered completion times for the associated Subprojects within a Project is not well understood. Completion times of Subprojects become better understood during the estimating and dependency phases of the Subprojects. As part of our Subproject planning process, PG&E considers how staggered Subproject completion timelines affect Ignition Risk and Outage Program Risk reduction. Subproject planning includes constraints analysis at both a Portfolio level and the Subproject level. For instance, Subproject constraints include permitting requirements, land rights,

resource availability, material availability, weather impacts, community impacts, and similar factors to build Subproject schedules. Portfolio constraints include cost recovery requirements that will be established in the CPUC Phase 2 Decision, as well as the Plan Mitigation Objective, Plan Tracking Objectives and other specific targets and objectives (as outlined in the EUP Guidelines Section 2.3). Throughout the Project and Subproject lifecycle, actual and forecasted execution timelines can change from the estimated timelines used initially to model Ignition Risk and Outage Program Risk reduction. These changes in the timing of forecasted and actual risk reduction from Subproject completion are fed back into our risk reduction model and are used to support updates to the annual Plan Tracking Objectives.[111] PG&E will adjust the workplan for future years based on the work completed to meet the EUP and CPUC Phase 2 Application targets and objectives. We will update the Plan Tracking Objectives to reflect any changes.

5. Incorporating Previously Scoped Projects Into the EUP

Project scoping and implementation is a long-term effort that often spans multiple years. PG&E incurs significant costs to develop an Undergrounding Project scope. Over the past years, we have scoped several Projects pursuant to the decision trees in approved WMPs. These Projects may not meet certain EUP requirements—for example, certain of the Projects may have been selected and scoped based on a previous version of the risk model.

PG&E has Undergrounding Projects in progress that we anticipate will be completed prior to the effective date of the EUP. These Projects are reasonable as they were prudently selected under the existing Project selection and decision-making process as vetted and approved in our WMPs. If any of these Projects are incomplete when the EUP begins, we would incorporate them into the EUP Portfolio and complete those Projects.

We expect only a small minority of the EUP mileage to be made up of previously-scoped Projects, and we would expect that many of these

[111] Controls to mitigate these impacts are described more in Chapter 5, Section C.1.c Controls to Maintain Adherence to Schedules (EUP Guidelines Section 2.5.1(c)).

Projects would meet the EUP eligibility criteria and significantly reduce Wildfire Risk. However, even If the Project does not meet all the EUP requirements, PG&E should be allowed to complete them because when they were selected and scoped PG&E forecasted that they significantly reduce wildfire risk based on the risk model at the time—the key factor in selecting and pursuing Projects in the EUP.

Further, it would be very disruptive to customers and communities where planning for undergrounding has already begun, often including acquisition of land rights from local customers, coordination with the municipality about paving plans and traffic controls plans, to cancel a Project simply due to the transition from GRC funding to EUP funding.

Therefore, it is reasonable to include these previously-scoped Projects in the EUP Portfolio. We would consider the risk reduction, miles, and unit cost of these Projects in the annual values included in the Target/Timeline Table.[112]

E. Chapter Summary

This chapter establishes PG&E's Project Acceptance Framework for identifying, evaluating, and prioritizing Undergrounding Projects. It explains how Circuit Segments move through four screens and how PG&E applies statutory and EUP Guidelines requirements at each stage. Overall, the chapter shows that PG&E's framework is designed to focus undergrounding where it can provide the greatest wildfire risk reduction, reliability benefit, and public safety value while remaining cost-efficient and operationally feasible. By combining threshold-based screening, benefit-cost comparisons across undergrounding and alternative mitigations, Project-level scoping, and Portfolio-Level prioritization, PG&E creates a transparent and repeatable process for selecting confirmed and Prioritized Projects. This framework supports development of Portfolio 0 and provides the structure for future updates as Project conditions, model outputs, and implementation constraints evolve.

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[112] The Target/Timeline Table is provided in Progress Report 0 as Table A-2 (in Attach. A), and as required in EUP Guidelines Section 2.3.1.k, PG&E has included an excel workbook in Attach. B, WP002 (EUP Target/Timeline Table).

F. Chapter 3 Supporting Attachments Index

The following workpapers/attachments support this chapter.

TABLE 3-15:
CHAPTER 3 SUPPORTING ATTACHMENTS/WORKPAPERS INDEX

Line No.	EUP Section	EUP Location	Workpaper / Table Name	File Name
1	3.C.4	Attachment A-5	Table C.17 Project GIS Data	PGE_Initial_2026-09-30_GIS Data_R0
2	3.D 3.D.3.a	Attachment B	WP003 (Project Prioritization and Decision Tree)	PGE_WP003_2026-09-30_Project Prioritization and Decision Tree_R0
3	3.D.2.a	Attachment B	WP001 (Mitigation Effectiveness Analysis)	PGE_WP001_2026-09-30_Mitigation Effectiveness Analysis_R0
4	3.D.2.a	Attachment B	WP006 (WBCA Whitepaper)	PGE_WP006_2026-~~09~~10-30_WBCA Whitepaper_R0
5	3.D.2.a	Attachment B	WP004 (WBCA Feedback Loop)	PGE_WP004_2026-09-30_WBCA Feedback Loop _R0
6	3.D.2.a	Attachment A-2	Progress Report Tabular Data (Tables C.6 – C.15)	PGE_Initial_2026-~~09-30~~11-02_Tabular Data_R0
7	3.D.2.a	Attachment D	SPD-37 Appendix 1 Data Submission	PGE_Initial_2026-~~09-30~~11-02_Attachment D_R0
8	3.D.5	Attachment B	WP002 (EUP Target / Timeline Table)	PGE_WP002_2026-~~09~~10-30_EUP Target Timeline Table_R0
9	3.C.4 3.D.4.a 3.D.5	Attachment A	Progress Report 0 Narrative	PGE_AtchA_2026-~~09~~10-30_Progress Report 0 Narrative_R0

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 4

CIRCUIT SEGMENT INFORMATION LISTS

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 4
CIRCUIT SEGMENT INFORMATION LISTS

A. Introduction

In this chapter, we address two issues required by Section 2.4.7 of the Electrical Undergrounding Plan (EUP) Guidelines: the preparation of the Circuit Segment Information Lists and information regarding other system hardening programs Pacific Gas and Electric Company (PG&E) conducts to reduce Wildfire and Outage Program Risk in the High Fire Threat District (HFTD)/High Fire Risk Areas (HFRA) outside of the EUP.

Section B lists the requirements in Senate Bill (SB) 884 and the EUP Guidelines addressed in this chapter.

Section C explains how tabular data created in compliance with the Project Acceptance Framework described in Chapter 3 is combined and sorted to create the required Circuit Segment Information Lists.

Section D describes PG&E's current system hardening programs that are conducted to reduce or eliminate Wildfire and Outage Program Risk on Circuit Segments outside of the EUP: (1) PG&E's existing Undergrounding Program; (2) Overhead System Hardening; and (3) Line Removal with or without Remote Grids. For each program, we provide a Project description, the approximate timeline for completion, Project status, and associated Wildfire Risk reduction.

Section E provides a chapter summary and Section F lists attachments supporting this chapter.

B. Undergrounding Plan Requirements

In Tables 4-1 and 4-2 below, we identify each of the statutory and EUP Guidelines requirements that are addressed in this chapter.

TABLE 4-1:
SB 884 REQUIREMENTS ADDRESSED IN CHAPTER 4

Line No.	Public Utilities Code Section	Legislative Requirement	Where Requirement is Addressed
1	8388.5(c)(2)	Identification of the undergrounding projects that will be constructed as part of the program, including a means of prioritizing undergrounding projects based on wildfire risk reduction, public safety, cost efficiency, and reliability benefits. Only undergrounding projects located in Tier 2 or Tier 3 HFTD or rebuild areas may be considered and constructed as part of the program.	Chapter 4

TABLE 4-2:
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS ADDRESSED IN CHAPTER 4

Line No.	EUP Guidelines Section	EUP Guidelines Requirement	Requirement Reference in Chapter 4
1	2.4.7	Required Circuit Segment Information Lists	Section C
2	2.4.7.1	Instructions for Circuit Segment information Lists	Section C.1
3	2.4.7.2	Information on Non-EUP Projects	Section D
4	Appendix B	A narrative describing how the tabular data can be combined and sorted to create the required Circuit Segment Information Lists.	Section C

C. Required Circuit Segment Information Lists (EUP Guidelines Section 2.4.7)

1. Instructions for Circuit Segment Information Lists (EUP Guidelines Section 2.4.7.1)

The Project Acceptance Framework uses a series of screens to evaluate Circuit Segments for the EUP.

As seen in Figure 1, Project Acceptance Framework Flowchart and described above, each screen requires the Large Electrical Corporation to create and review progressively smaller sets of Circuit Segments which satisfy various criteria and have different levels of information determined, until they finally become Confirmed Projects and Prioritized Projects. The full lists of Circuit Segments which have reached these stages can be generated from the data submission tables described in Appendix C. Each Progress Report, beginning with Progress Report 0 (see Section 2.6), will include the data submission for these lists in a tabular format that can be accessed by members of the public.

The table below describes the lists utilized in the Project Acceptance Framework process, the relevant information they contain, and the tables that can be joined to generate the lists.

As described in Chapter 3, PG&E applies the Project Acceptance Framework to evaluate Circuit Segments for the EUP, including the Project evaluation steps described in four consecutive screens. Consistent with Section 2.4 of the EUP Guidelines, this process applies standardized, risk-based criteria to progressively refine the population of the Circuit Segments and develop Undergrounding Projects, Confirmed Projects and Prioritized Projects.

Section 2.4.7.1 of the EUP Guidelines, which is addressed in this chapter, provides instructions for generating the full list of Circuit Segment and Project information that have reached applicable stages of the Project Acceptance Framework.

PG&E provides this information through Attachment B, Workpaper 032, Circuit Segment List, and the data submission tables in Progress Report Attachment A-2. Attachment B, Workpaper 032 Circuit Segment List (WP032), provides the complete inventory of Circuit Segments in PG&E's service territory that serves as the foundational dataset for the Project Acceptance Framework. For each Circuit Segment, the workpaper provides the Circuit Segment ID, associated Circuit ID, segment length, Project ID where applicable, county, HFTD tier, and indicators identifying whether the

Circuit Segment is within a Rebuild Area, is In Area, and is eligible for the EUP.

Below describes the information in the Circuit Segment Information List.

- **All Circuit Segments List:** PG&E lists all Circuit Segments in our service territory.
- **In-Area Circuit Segments List:** PG&E develops this list by removing all Circuit Segments outside the Tier 2 or Tier 3 HFTD and Fire Rebuild Areas from the All Circuit Segments List.
- **Eligible Circuit Segments List:** PG&E develops this list by applying the Project-Level Thresholds (outlined in Chapter 7, Section M.1) to all In-Area Circuit Segments. Projects that are above the Project-Level Thresholds are included in the list of Eligible Projects.
- **Ineligible Circuit Segments List:** PG&E develops this list by applying the Project-Level Thresholds (outlined in Chapter 7, Section M.1) to all In-Area Circuit Segments. Projects that fall below the Project-Level Thresholds are included in the list of ineligible Projects.

The Progress Report data submission tables in Attachment A-2 provide the additional information needed to identify and track Projects as they advance through the Project Acceptance Framework. The data in Workpaper 032 may be joined with the applicable data submission tables provided in Attachment A-2 Progress Report Tabular Data that generates the lists of Circuit Segments that have reached the relevant framework stages, including Confirmed Projects and Prioritized Projects. Table C.9, the Screen History Table, identifies the screens that each Circuit Segment or Project has passed. Table C.10, the Project Table, provides the Projects that have advanced through Screens 2, 3, or 4, including the information used to identify Undergrounding Projects, Confirmed Projects, and Prioritized Projects. All information related to Circuit Segment eligibility and EUP inclusion is provided in Table C.6. Non-EUP Projects located in Tier 2 or Tier 3 HFTD are listed in Table C.22. See below for more information about each list:

- **Undergrounding Projects List:** PG&E defines an Undergrounding Project as a Circuit Segment that has passed Screen 2 and is eligible for undergrounding. The list of Undergrounding Projects is the basis of

Table C.10 and the mitigation options compared in Screen 2 can be reviewed for those Circuit Segments in Table C.11 (see Chapter 3, Section D.2).

- **Confirmed Projects List:** PG&E develops the Confirmed Projects List as Projects progress through the Screen 3 assessment (outlined in Chapter 3, Section D.3.a.1-8). This list can be found in Table C.10.
- **Prioritized Projects List:** PG&E applies the Screen 4 prioritization approach described in Chapter 3, Section D.4 to develop the final List of Confirmed Projects that have been identified in Screen 3. This list can be found in Table C.10.
- **Non-EUP Projects List:** This list is a subset of the In-Area Circuit Segments List, as it includes all non-EUP distribution undergrounding or other system hardening Projects in a Tier 2 or Tier 3 HFTD. This list can be found in Table C.22.

Beginning with Progress Report 0, PG&E will update the applicable tables in Progress Report Attachment A-2 as required by the EUP Guidelines. Together, Attachment B, Workpaper 032 Circuit Segment List (WP032), and the Progress Report data submission tables provide the publicly accessible tabular information necessary to generate the Circuit Segment and Project lists used in the Project Acceptance Framework.

D. Information on Non-EUP Projects (EUP Guidelines Section 2.4.7.2)

The EUP must include information on any distribution undergrounding or other system hardening project in a Tier 2 or 3 High Fire Threat District that is funded or in the Project Planning or Construction Phases that is not included in the 10-Year EUP ("Non-EUP Project"). The Large Electrical Corporation must include this information in the Circuit Segment Identification Tables as described in Appendix C.1.6. The Large Electrical Corporation is not required to apply the screens to non-EUP Projects.

The Large Electrical Corporation must also provide a brief overview of all non-EUP Undergrounding programs and all other distribution system hardening programs aimed at reducing Ignition Risk and Outage Program Risk. The Large Electrical Corporation must include the timeline for completion of Non-EUP Projects, their Project Status, and their associated risk reduction. The overview must discuss how the selection process for these Non-EUP Projects and programs is different from the EUP and how they will be coordinated with the EUP.

All of the information above must be updated in each Progress Report. The Large Electrical Corporation must also include a narrative describing how these projects are accounted for in the Risk Modeling Methodology.

PG&E's system hardening programs approved by the California Public Utilities Commission (CPUC or Commission) through the General Rate Case (GRC) include: (1) Undergrounding; (2) Overhead System Hardening; and (3) Line Removal with and without Remote Grids. Each program is specifically designed to reduce Ignition Risk and Reliability Risk. PG&E does not address Rule 20 Undergrounding Projects in our EUP as they are primarily completed for aesthetic purposes rather than reducing Ignition Risk and Outage Program Risk.

PG&E includes in the Progress Report a list of all non-EUP system hardening Projects, including the timeline for completion, Project Status, and associated risk reduction (see Progress Report 0 Table C.22).

Each non-EUP system hardening program (i.e. Overhead Hardening and Line Removal), timeline for completion and estimated risk reduction are described in detail below. In addition, PG&E deploys Hybrid Projects that consist of a combination of undergrounding, overhead hardening, and/or line removal. Depending on the mitigations selected for a Project, PG&E will follow the steps for each mitigation and apply it to the selected portion of the Circuit Segment.

1. GRC-Funded Undergrounding Program

a. Program Description

PG&E's existing Undergrounding Program is focused on mitigating Ignition Risk and Outage Program Risk caused by distribution overhead assets. The primary benefits provided by undergrounding are: (1) near permanent ignition risk reduction from overhead electric distribution equipment; and (2) avoiding customer reliability impacts from deploying Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) to mitigate Ignition Risk on overhead lines.

Undergrounding is PG&E's preferred solution for mitigating Ignition Risk in the highest-risk areas where the long-term benefits of undergrounding include greater wildfire risk reduction, reliability improvements, and ongoing vegetation management and operational cost avoidance. Undergrounding also mitigates the potential for harm or injury to members of the public by reducing the likelihood of contact with an energized line.

PG&E forecasts that we will underground 1,205 circuit miles during the 2023-2026 period. PG&E's plan to underground 307 circuit miles in 2027 was approved by Energy Safety in its decision on PG&E's 2026-2028 WMP[113] and is pending approval in PG&E's 2027 GRC.

b. Timeline and Project Status

A typical timeline for all Undergrounding Project activities over the Project lifecycle is approximately four years (one to two years for pre-construction activities, one year for construction and one year for post-construction activities).

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[113] Office of Energy Infrastructure Safety Decision, Pacific Gas and Electric Company 2026-2028 Base Wildfire Mitigation Plan (Feb. 5, 2026), p. 30, available at: < <https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=60177&shareable=true&_gl=1*1y1sal*_ga*MTQ0NzAwNTg2LjE3NzEwMDAwMTE.*_ga_69TD0KNT0F*czE3NzMzMzkxMTMkbzMkZzAkdDE3NzMzMzkxMTMkajYwJGwwJGgw*_ga_340RFMFNWY*czE3NzMzMzkxMTMkbzMkZzAkdDE3NzMzMzkxMTMkajYwJGwwJGgw*_ga_DCP197HRSL*czE3NzMzMzkxMTMkbzMkZzAkdDE3NzMzMzkxMTMkajYwJGwwJGgw> (accessed Mar. 12, 2026).

Undergrounding electric distribution system assets follows the same general process as most utility construction work. The following describes the phases of an Undergrounding Project:

(1) Project Planning and Scoping: The Undergrounding Program focuses on circuits in the HFTD and Fire Rebuild Areas.[114] Project planning and scoping consists of identifying, developing, and defining an Electric Distribution asset requiring undergrounding. In scoping Projects, PG&E balances risk reduction, constructability, and affordability.

(2) Engineering and Design: Engineering and design consists of developing a comprehensive design for the new assets to be installed underground and identifying materials needed to execute the Project. This includes designing the trench, bore tunnel, or other underground pathway for the conduit and electric cable, as well as the boxes, transformers or other connections needed to integrate with customer services. The Project scoping and design phases address and plan for constructability issues, which include the local geology (whether hard rock exists), existing underground utilities (including water, natural gas and drainage systems), plans for future road widening, sensitive environmental and/or cultural resources, and other factors.

(3) Material Acquisition: Material acquisition includes sourcing, purchasing, storing, and staging materials needed for Undergrounding Projects. Material acquisition also includes developing a sustainable supply chain to ensure availability of materials and securing favorable rates through long-term contracting.

(4) Permitting and Land Rights: Undergrounding Projects may encounter sensitive resources such as waterways, animal habitats, and cultural resources. PG&E implements construction impact mitigation measures and best management plans to mitigate

[114] The Undergrounding Program previously included circuits in the HFTD, HFRA and Fire Rebuild Areas.

disturbances and engages key agencies, cities, counties, tribes, individuals and other stakeholders early and often to mitigate risks and issues associated with permitting and environmental considerations. PG&E may adjust Project designs or construction plans as a result of this process. Additionally, for undergrounding work on private property, PG&E acquires the appropriate land rights, which generally involve easements. PG&E's existing land rights for overhead power lines often do not grant the right to install underground assets in the same configuration and thus require new or expanded land rights.

(5) Construction: The actual construction phase of an Undergrounding Project is the most labor-intensive and community impacting phase of the Project. Traffic control is often deployed to keep construction crews and community members safe as undergrounding is frequently performed in or adjacent to public roads. Construction can also be subdivided into the following two phases (although the phases may overlap): (1) civil construction including trenching and installing the conduit and boxes; and (2) electric construction pulling cable through the installed conduit and connecting the cable to equipment installed inside the boxes. At the end of the construction phase, service to impacted customers is converted from the existing overhead powerlines to the new underground lines and the deenergized overhead assets are removed.

(6) Quality Control and Inspections: Quality inspection of underground assets is performed throughout the construction phase, including when the trench is open or electric cables are being pulled and connected to equipment. At the end of construction, PG&E conducts a fire safe audit prior to energizing the new underground line. Any quality validation or inspection activities must be carefully timed and executed in partnership with construction activities.

(7) Mapping, Documentation, and Closeout: Mapping, documentation, and closeout involves permanently documenting the assets that have been installed as part of the Undergrounding Projects and

removing from the active maps the overhead lines that have been eliminated, and other administrative Project closeout activities.

PG&E engages with customers, property owners, and communities through the entire process of planning and executing an Undergrounding Project to partner, coordinate, and share information.[115]

c. Risk Reduction

Relocating overhead distribution lines underground is the most effective way to achieve near permanent Wildfire Risk reduction and significantly reduces Outage Program Risk from PSPS and EPSS. PG&E assessed the effectiveness of each of Alternative Mitigation (undergrounding, overhead hardening, overhead hardening with EPSS, line removal) against more than 2,700 outage combinations that occurred in PG&E's HFTD during the 2015-2024 wildfire seasons. Undergrounding primary distribution lines is approximately 98 percent effective at mitigating Wildfire Risk.

PG&E also analyzed the reliability performance on Circuit Segments where undergrounding was performed in 2022 and 2023 to quantify overall improvements to service reliability. PG&E's analysis included approximately 750 outages between 2021 and 2024 and showed an approximate 90 percent reduction in faults that resulted in sustained outages after the undergrounding work was completed.

Our 2027 GRC forecast requests approval of 307 circuit miles of undergrounding and estimates that this will achieve 2.8 percent of Wildfire Risk reduction in 2027. If the Commission does not approve 307 miles in PG&E's 2027 GRC, PG&E will update our 2027 risk reduction forecast based on the number of miles approved.

2. Overhead System Hardening

a. Program Description

Overhead System Hardening includes replacement of bare overhead primary conductor and associated framing with conductor

[115] See A.25-05-009, PG&E Ex-04, pp. 7-25 to 7-28.

insulated with abrasion resistant polyethylene coatings (often referred to as “covered conductor” or “tree wire”) that can be an effective mitigation in certain instances to prevent ignitions caused by distribution lines. Installing covered conductor can help reduce the likelihood of faults in instances such as line-to-line contacts, tree branch contacts, and faults caused by animals. Installing covered conductor on secondary lines has similar resilience to faults or risk events as installing it on primary lines. In addition to replacement of conductor, Overhead System Hardening reduces Wildfire and Reliability Risk through the following foundational activities: (1) primary and secondary covered conductor replacement; (2) pole replacement, which may include adding additional poles, where the poles are not strong enough for the covered conductor; (3) replacement of non-exempt equipment; (4) replacement of overhead distribution line transformers; (5) framing and animal protection upgrades; and (6) vegetation clearing. Further detail of each of these activities is outlined below:

(1) Primary and Secondary Covered Conductor Replacement: Replacement of bare overhead primary conductor and associated framing with conductor insulated with abrasion resistant polyethylene coatings (covered conductor or tree wire) can be an effective mitigation in certain instances to prevent ignitions caused by distribution lines. Installing covered conductor can help reduce the likelihood of faults including but not limited to: line-to-line contacts, tree branch contacts, and faults caused by animals. Installing covered conductor on secondary lines has similar resilience to transient events to installing it on primary lines.

(2) Pole Replacements: Evaluating all existing poles where a system hardening Project is planned is necessary to determine whether those poles meet the strength requirements to withstand the new, heavier covered conductor and associated equipment. PG&E then replaces poles based on that evaluation. Often, most poles in the scope of an overhead hardening Project will need to be replaced because they do not meet PG&E standards. In addition, new poles

can be added as needed to support additional conductor weight and loading.

(3) Replacement of Non-Exempt Equipment: Replacing existing primary line equipment such as fuses/cutouts and switches with equipment that is certified by the California Department of Forestry and Fire Protection (CAL FIRE) as low fire risk is another component of PG&E's System Hardening Program. This replacement work eliminates overhead line equipment and devices that may generate exposed electrical arcs, sparks, or hot material during their operation.

(4) Replacement of Overhead Distribution Line Transformers: Upgrading transformers with newer transformers that contain fire resistant "FR3" insulating fluid to be consistent with PG&E's current equipment standards. "FR3" insulating fluid, a natural ester derived from renewable vegetable oils, provides improved fire safety, transformer life, increased load capability, and environmental benefits. In addition, new transformers are manufactured to achieve higher Department of Energy electrical efficiency standards.

(5) Framing and Animal Protection Upgrades: Replacing crossarms with composite arms, wrapping jumpers, and installing animal protection upgrades reduces animal contacts and pole-related ignition risks.

(6) Vegetation Clearing: Clearing vegetation undergrowth to access facilities to execute a Project and bring the vegetation clearance up to standard for the newly-installed infrastructure is a critical component of overhead hardening. Regulatory requirements mandate four feet of clearance throughout the year. If there is a change to a line's profile, including using taller poles or wider cross arms, the vegetation must be cleared to be consistent with any profile changes and provide the required clearing for new overhead lines. This clearance must be maintained over the life of the overhead assets.

b. Timeline and Project Status

Overhead System Hardening Projects have similar cycle times as Undergrounding Projects as both project types navigate scoping, permitting, and pre-construction activities. Overhead System Hardening Projects take approximately 17 months from Project initiation (identified at the scoping phase of a Project) to Project completion (construction end).[116]

Overhead System Hardening is tracked and managed as part of PG&E's System Hardening Program. Projects are tracked starting with Project scoping when mitigations are first selected.

PG&E's System Hardening Program generally begins tracking non-EUP Undergrounding Projects in the HFTD once a Non-EUP Project has been identified and given a unique identifier for reporting. When Non-EUP Projects reach this stage, we will report them in Table C.22 of our Progress Reports.

c. Risk Reduction

Overhead System Hardening provides benefits for Wildfire Risk reduction. Based on an analysis of projected performance of overhead hardened facilities on more than 2,700 outage types, PG&E estimates that, on average, Overhead System Hardening can reduce 67 percent of the distribution overhead asset ignitions caused by equipment failures or external contact/strikes with energized lines, such as vegetation tree strikes.[117] When used in combination with EPSS and Downed Conductor Detection (DCD), Overhead System Hardening can, on average, reduce Wildfire Risk by approximately 79 percent. See Workpaper 001, Mitigation Effectiveness Analysis, for additional information on PG&E's mitigation effectiveness methodology.

PG&E forecasts in the 2027 GRC that we will achieve approximately four percent of Wildfire Risk reduction from 2027 to 2030 by installing

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116 Analysis based on subprojects completed between 2018-2024, excluding Fire Rebuild work.

117 PG&E 2026-2028 Wildfire Mitigation Plan R3, Vol. 1, (Dec. 30, 2025), Section 8.2.5.

approximately 760 miles of covered conductor.[118] If the Commission does not approve our full 2027 GRC Overhead System Hardening forecast, PG&E will update our risk reduction forecast based on the number of covered conductor miles approved.

3. Line Removal Program

a. Program Description

The Line Removal Program is a cost-effective Wildfire Risk mitigation and a form of system hardening that may be considered where operationally feasible, as part of PG&E's broader wildfire risk mitigation strategy. Line removal is pursued when a distribution line is no longer needed for operational or service reasons and its continued presence increases Ignition Risk. Consistent with PG&E's WMP, targeted line removal may be enabled through several implementation pathways.[119] These include:

(1) Removal of Idle Facilities: Idle facilities are electric distribution line segments that are no longer serving customer load or operational needs. Where an idle facility is no longer required for future system operations or contingency use, PG&E may remove the line to permanently eliminate the associated Ignition Risk.

(2) Circuit Re-route: PG&E may evaluate a Circuit Segment for removal if system reconfiguration, new construction, or other infrastructure upgrades mean that its associated load is now permanently served through an alternate path and the original line segment is no longer required for normal operations, contingency support, or reliability purposes.

(3) Remote Grids: PG&E can remove overhead distribution lines by installing remote grids—standalone power systems that provide continuous, permanent electric service—to meet customer energy needs in remote locations serving a small number of customers.

(4) Line Elimination Incentive Program (LEIP): Through this program, PG&E enters into an agreement with a property owner in a wildfire

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[118] A.25-05-009, PG&E Ex-04, p. 7-22, Table 7-6.

[119] 2026-2028 WMP, Section 8.2.9.2.

risk area under which PG&E removes the electric line serving the property and provides compensation. Under the LEIP agreement, the customer assumes responsibility to provide their own energy supply, thereby allowing PG&E to permanently remove the distribution line to eliminate the associated Ignition Risk.

(5) Land Purchases: In limited circumstances where Wildfire Risk cannot be reasonably mitigated through other system hardening measures, PG&E may purchase land from a property owner and discontinue electric service to the property.

Remote grids, LEIP, and land purchases are implementation mechanisms that may enable line removal; these mitigations are evaluated using the same underlying risk mitigation framework as other system hardening mitigations.

b. Timelines and Project Status

The timeline of a Line Removal Project varies based on the implementation method. Where the implementation method is associated with installing infrastructure such as a Remote Grid, the timeline is typically longer than for pathways where installation of new infrastructure is not required. Remote Grid Projects can have similar timelines as Undergrounding and Overhead System Hardening Projects because Remote Grid Projects involve scoping, land rights and permitting where applicable, and engineering and other pre-construction activities. The end-to-end timeline for Remote Grid Projects is approximately 24 months. Remote Grid Projects requiring discretionary permitting can take longer.

To the extent that an idle facilities Project, circuit re-route, LEIP or land purchase Project is not dependent on an associated infrastructure installation Project (e.g., a LEIP Project and a Remote Grid Project located on the same end-of-line Circuit Segment), these Project types may have timelines shorter than 24 months.

In addition, all line removal implementation methods may have permitting requirements for the line removal work that can impact the timeline, in addition to the pre-construction activities and the line removal work itself.

Line removal Projects enabled by Remote Grid or LEIP are tracked and managed by PG&E's Remote Grid Program Management team which implements standardized PG&E processes for evaluating, designing, deploying, and operating Remote Grids.

c. Risk Reduction

PG&E forecasts that we will achieve approximately 0.04 percent of Wildfire Risk reduction from our line removal program from 2027-2030, based on our 2027 GRC target. Line Removal eliminates 100 percent of the risk associated with the former overhead distribution lines.[120]

4. Selection Process for Non-EUP Projects and Differences With EUP Project Selection

Consistent with the requirements in the EUP screen process (see EUP Guidelines Section 2.4), Overhead System Hardening and other system hardening mitigations will be selected using the same methodology where a Circuit Segment does not meet the requirements for an Undergrounding Project.

For each Circuit Segment that is not selected for undergrounding, PG&E will identify an Alternative Mitigation based on the results of economic analyses (cost benefit analysis and net benefit) and the Project selection framework, including the EUP decision tree. As a result of that process, PG&E will designate a Circuit Segment for Overhead System Hardening or, if appropriate, find an opportunity for Line Removal which could entail deployment of a Remote Grid or the LEIP.

5. How Non-EUP Projects Are Accounted for in the Risk Modeling Methodology

All system hardening Projects are modeled the same. There is no difference in how we model non-EUP system hardening Projects compared to EUP Projects.

Circuit Segments that have been hardened outside of the EUP could be identified as Eligible Circuit Segments under the Screen 1 criteria (located in the HFTD and meet one of the Project-level thresholds) but they would be

120 2026-2028 WMP, p. 179, Table 8-1.

excluded from further consideration during Screen 3 filtering if the Circuit Segment or portions of the segment have already been hardened and thus would be excluded from consideration in subsequent screens. (See Chapter 3, Section D.3.a.) We also exclude any privately-owned distribution lines.

Non-EUP Projects would be excluded when we report instantaneous and cumulative risk over various time periods since only Confirmed Projects are included in the instantaneous and cumulative risk calculations.[121] PG&E will account for the risk reduced by Non-EUP Projects when reporting changes to Circuit Segment information as required by EUP Guidelines Section 2.4.2.1 and when recording new baselines each year as required by EUP Guidelines Section 2.7.5, Core Capability 6.

6. Coordination with the EUP Projects

Non-EUP system hardening work will be coordinated with EUP Undergrounding Projects.

PG&E's system hardening scoping process accounts for future grid needs and includes collaboration with distribution planning and operating engineers so we can ensure our Project scope reflects anticipated future growth and operational needs. Specifically, PG&E's planning and operating engineers are included throughout the review and approval process from when a Project is first identified for possible system hardening to when the final job package is created and the Project design is estimated for construction.

For Projects and Subprojects which may opportunistically be planned for coordination during construction, PG&E also employs strategies to gain efficiencies across non-EUP and EUP work. These include, but not limited to, shared permits with local and state jurisdictions, shared contractor resources and contracting strategies, shared outage windows limiting customer impact, shared laydown or staging yards, material procurement strategies, and shared Project and construction management.

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[121] See EUP Guidelines, p. 36, Section 2.7.5, Core Capability 4: Approximating Future Risk and Accumulation of Ignition Risk and Outage Program Risk Over Time.

E. Chapter Summary

This chapter explains how PG&E satisfies the EUP Guidelines requirements in Section 2.4.7 by producing the Circuit Segment Information Lists and by identifying other system hardening efforts in the HFTD/HFRA that are outside of the 10-Year EUP. It describes how the standardized data developed through the Project Acceptance Framework is combined and sorted to generate the full set of required lists, including all Circuit Segments, In-Area, Eligible/Ineligible, Undergrounding Projects, Confirmed Projects, Prioritized Projects, and Non-EUP Projects lists.

This chapter also provides a concise overview of PG&E's non-EUP system hardening programs—GRC funded undergrounding, overhead system hardening, and line removal—by describing program scope, typical timelines and Project status, and the associated wildfire and reliability risk reduction. By documenting how these activities are tracked, reported, and incorporated into risk modeling, and by explaining how non-EUP work will be coordinated with EUP Projects, this chapter establishes transparency on both the EUP Project pipeline and the broader portfolio of system hardening work that collectively reduces Wildfire and Outage Program Risk.

F. Chapter 4 Supporting Attachments Index

The attachments in Table 4-3 below support this chapter.

TABLE 4-3:
CHAPTER 4 SUPPORTING ATTACHMENTS INDEX

Line No.	EUP Section	EUP Location	Workpaper/Table Name	File Name
1	4.C.1	Attachment A-2	Progress Report 0 – Table C.6 Circuit Segment Identification Table	PGE_Initial_2026-09-30_T6_R0
2	4.C.1	Attachment A-2	Progress Report 0 – Table C.9 Screen History Table	PGE_Initial_2026-09-30_T9_R0
3	4.C.1	Attachment A-2	Progress Report 0 – Table C.10 Project Table	PGE_Initial_2026-09-30_T10_R0
4	4.C.1	Attachment A-2	Progress Report 0 – Table C.11 Screen 2 Table	PGE_Initial_2026-09-30_T11_R0
5	4.D	Attachment A-2	Progress Report 0 – Table C.22 Non-EUP Projects	PGE_Initial_2026-09-30_T22_R0
6	4.D.2.2	Attachment B, WP001	Mitigation Effectiveness Analysis	PGE_WP001_2026-09-30_Mitigation Effectiveness Analysis_R0
7	4.C.1	Attachment B, WP032	Circuit Segment List	PGE_WP032_2026-09-30_Circuit Segment List_R0

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 5

TIMELINES, WORKFORCE DEVELOPMENT, COSTS AND BENEFITS, AND NON-RATEPAYER FUNDING SOURCES

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 5
TIMELINES, WORKFORCE DEVELOPMENT, COSTS AND BENEFITS, AND NON-RATEPAYER FUNDING SOURCES

A. Introduction

In this chapter, we address the following issues required by Section 2.5 of the Electrical Undergrounding Plan (EUP) Guidelines: (1) EUP Project timeline and targets; (2) our workforce development plan; (3) the costs and benefits of undergrounding; and (4) the availability of non-ratepayer funding sources for EUP Projects.

In Section B, we list the requirements in Senate Bill (SB) 884 and the EUP Guidelines that are addressed in this Chapter.

In Section C, we provide a Target/Timeline table outlining the work we plan to complete, unit costs, and changes in Wildfire and Reliability Risk for each year of the EUP. We describe the Project Management Template we will use to track and communicate each Project's schedule and the controls in place to adhere to the schedule.

We then describe our workforce development plan including resource needs, recruiting and hiring strategy, training, third-party contracting, our plans for addressing resource constraints, and how we will manage potential impacts among the EUP and traditional safety and reliability work.

We next present an evaluation of project costs and benefits, the Benefit Cost Ratio (BCR) calculation, inputs into the Wildfire Benefit Cost Analysis (WBCA) model, and cost containment strategies.

In Section D, we describe our plan for identifying, applying for, and tracking non-ratepayer funds to reduce ratepayer costs for the EUP.

Section E provides a brief conclusion and Section F includes a list of attachments supporting this chapter.

B. Undergrounding Plan Requirements

In Tables 5-1 and 5-2 below, we identify each of the statutory and EUP Guidelines requirements addressed in this chapter.

TABLE 5-1:
SB 884 REQUIREMENTS ADDRESSED IN CHAPTER 5

Line No.	Public Utilities Code Section	Legislative Requirement	Where Requirement is Addressed
1	8388.5(c)(3)	Timelines for the completion of identified and prioritized undergrounding projects and unit cost targets and mileage completion targets for each year covered by the plan.	Section C.1
2	8388.5(c)(5)	A plan for utility and contractor workforce development.	Section C.2
3	8388.5(c)(6)	An evaluation of project costs, projected economic benefits over the life of the assets, and any cost containment assumptions, including the economies of scale necessary to reduce Wildfire Risk and mitigation costs and establish a sustainable supply chain.	Section C.3
4	8388.5(j)	Each large electrical corporation participating in the program shall apply for available federal, state, and other non-ratepayer moneys throughout the duration of its approved undergrounding plan, and any moneys received as a result of those applications shall be used to reduce the program's costs on the large electrical corporation's ratepayers.	Section D

TABLE 5-2:
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS ADDRESSED IN CHAPTER 5

Line No.	EUP Guidelines Section	EUP Guidelines Requirement	Requirement Reference in Chapter 5
1	2.5	Timelines, Workforce Development, Costs and Benefits, and Non-Ratepayer Funding	Sections C & D
2	2.3.1 and 2.5.1	Project Timelines and Targets	Section C.1
3	2.5.2	Workforce Development Plan	Section C.2
4	2.5.3	Costs and Benefits	Section C.3
5	2.5.4	Non-Ratepayer Funding Sources	Section D

C. Project Timelines, Workforce Development Plan, Costs and Benefits, and Non-Ratepayer Funding Sources (EUP Guidelines Section 2.5)

The Timelines, Workforce Development, Costs and Benefits, and Nonratepayer Funding components are the plan components required by Sections 8388.5(c)(3), (c)(5), (c)(6) and (j).

1. Project Timelines and Targets (EUP Guidelines Section 2.5.1)

Section 8388.5(c)(3) requires an EUP to include, "[t]imelines for the completion of identified and prioritized undergrounding projects, and unit cost targets and mileage completion targets for each year covered by the plan." To fulfill this component, the EUP must contain:

a. The Target/Timeline Table described in Section 2.3.1.

b. A project management template that will be used to track and communicate each project's schedule and milestones. The project management template should include dates for scoping, planning/design, permitting/dependencies, pre-construction, construction, and completion.

c. A description of controls that will be in place to ensure the schedules are maintained.

a. The Target/Timeline Table (EUP Guidelines Section 2.5.1(a))

PG&E presents our Target/Timeline table in Chapter 2, Section D.1 as required by Section 2.3.1 and Appendix B.1 of the EUP Guidelines. The Target/Timeline Table[122] includes information about the timelines for completion of projects, unit cost targets, mileage targets, anticipated start and end dates, risk reduction, and cost targets for each year of the EUP.

b. Subproject Management Template (EUP Guidelines Section 2.5.1(b))

PG&E will report scheduled completion dates for Confirmed Projects in a project management template as required by the EUP Guidelines. PG&E's template will report at the Subproject level, a more granular view than the project-level. We labeled this template the Sub-Project

[122] The Target/Timeline Table is provided in Progress Report 0 as Table A-2 (in Attach. A), and as required in EUP Guidelines Section 2.3.1.k, PG&E includes an excel workbook in Attach. B, WP002 (EUP Target/Timeline Table).

Management Template (SPM Template) to be clear on the level of detail provided. For each Confirmed Project, we will track in the SPM Template the forecasted completion dates of key milestones for all Subprojects (including Undergrounding Subprojects and Non-Undergrounding Subprojects). We will include the milestones required in EUP Guidelines Section 2.5.1 (i.e., scoping, designing, permitting, pre-construction, construction, and completion/de-energization), where appropriate.[123] For consistency in reporting across the Subproject Table (C.14) and the SPM Template, we use the Subproject milestones listed in the "status_current" field of the Subproject Table (C.14) for the SPM Template. The Subproject milestones of these activities are different than what is described in Chapter 4, Section D.1.b Timeline and Project Status. For clarity, in Table 5-3 below, we map the milestones in PG&E's SPM Template to the milestones required in EUP Guidelines Section 2.5.1 and the milestones described in Chapter 4, Section D.1.b Timeline and Project Status.

PG&E will update the SPM Template every six months as new Subprojects are added to the Portfolio and schedules change. The SPM Template will be attached as Table C.23 to the Progress Report.

[123] An explicit pre-construction milestone is not included in the SPM template as pre-construction milestones are considered the same as all milestones prior to construction, including Scoping, Planning and Design, Permitting and Dependencies.

TABLE 5-3:
PG&E'S SUBPROJECT MANAGEMENT TEMPLATE DATA FIELDS AND ALIGNMENT TO PROJECT PHASES DESCRIBED IN CHAPTER 4

Line No.	Subproject Management (SPM) Template			Chapter 4, Section D.1.b Timeline and Project Status	
1	EUP Guidelines Requirements for PM Template Milestone	PG&E's SPM Template Column Header, Forecasted Completion Date	Description of Milestone/Subproject Status Completion Milestone	Project Phase[(a)]	Description
2	ID Fields	Project ID	Numerical assignment for a project to associate the project with the Subproject reported in this SPM template	N/A	N/A
		Subproject ID	Numerical assignment for a Subproject.	N/A	N/A
3	Scoping	Scoping	Date of the Subproject scope delivery.	Project Planning and Scoping	The Undergrounding Program focuses on circuits in the HFTD and Fire Rebuild Areas. Project planning and scoping consists of identifying, developing, and defining an Electric Distribution asset requiring undergrounding. In scoping projects, PG&E balances risk reduction, constructability, and affordability when selecting the appropriate mitigation approach.
4	Planning and Design	Designing	Date of the Issue for Construction (IFC) design. IFC Design is the final output of the design prior to release to the field for construction to begin.	Engineering and Design	Engineering and design consists of developing the comprehensive design for the new assets to be installed underground and identifying materials needed to execute the project. This includes designing the trench, bore tunnel, or other underground pathway for the conduit and electric cable, as well as the boxes, transformers or other connections needed to integrate with customer services. The project scoping and design phases address and plan for constructability issues, which include the local geology (whether hard rock exists), existing underground utilities (including water, natural gas and drainage systems), plans for future road widening, sensitive environmental and/or cultural resources, and other factors.
5	Permitting and Dependencies	Permitting	Date of the Environmental Release to Construction (ERTC), which includes land acquisition, environmental permits, private, local and state jurisdictional permits.	Permitting and Land Rights	Undergrounding projects may encounter sensitive resources such as waterways, animal habitats, and cultural resources. PG&E implements construction impact mitigation measures and best management plans to mitigate disturbances and engages key agencies, cities, counties, tribes, individuals and other stakeholders early and often to mitigate risks and issues associated with permitting and environmental considerations. Additionally, for undergrounding work on private property, PG&E acquires the appropriate land rights, which generally involve easements. PG&E's existing land rights for overhead power lines often do not grant the right to install underground assets in the same configuration and thus require new or expanded land rights.
6	Pre-construction	Ready For Construction (Mobilization)	Date Civil Construction begins. Civil construction includes subsurface asset installation of conduit, boxes, pads, and other civil-discipline work.	Materials Acquisition[(b)]	Material acquisition includes sourcing, purchasing, storing, and staging materials needed for undergrounding projects. Material acquisition also includes developing a sustainable supply chain to ensure availability of materials and securing favorable rates through long-term contracting.

TABLE 5-3
PG&E'S SUBPROJECT MANAGEMENT TEMPLATE DATA FIELDS AND ALIGNMENT TO PROJECT PHASES DESCRIBED IN CHAPTER 4
(CONTINUED)

Line No.	Subproject Management (SPM) Template			Chapter 4, Section D.1.b Timeline and Project Status	
7	Construction	Construction in Progress	N/A – "Construction in Progress" is inferred between milestone dates "Ready for Construction" and "Construction Complete." It is therefore not tracked as a standalone milestone.	Construction	The actual construction phase of an undergrounding project is the most labor-intensive and community impacting phase of the project. Traffic control is often deployed to keep construction crews and community members safe as undergrounding is frequently performed in or adjacent to public roads. Construction can also be subdivided into the following two phases (although the phases may overlap): (1) civil construction including trenching and installing the conduit and boxes and (2) electric construction pulling cable through the installed conduit and connecting the cable to equipment installed inside the boxes. At the end of the construction phase, service to impacted customers is converted from the existing overhead powerlines to the new underground lines.
8	Complete	Construction Complete / Overhead De-energized	Final date of all new asset installation, energization, and de-energization of retired assets where applicable, as well as successful QA pass. After this milestone, the project is in "Construction Complete" status.	Quality Control and Inspections	Quality inspection of underground assets is performed throughout the construction phase, including when the trench is open or electric cables are being pulled and connected to equipment. At the end of construction, PG&E conducts a fire safe audit prior to energizing the new underground line. Any quality validation or inspection activities must be carefully timed and executed in partnership with construction activities.
9	N/A - Post-Construction activities	N/A	N/A	Mapping, Documentation, and Closeout	Mapping, documentation, and closeout involves permanently documenting the assets that have been installed as part of the undergrounding projects and removing from the active maps the overhead lines that have been eliminated, and other administrative project closeout activities.

(a) Subproject phases (e.g., Project Planning and Scoping) may align to multiple Project phases as defined in Chapter 4, Section D.1.b Timeline and Project Status. This table defines the active phase at the Subproject level.
(b) Material Acquisition is completed in parallel to the Design, Permitting, Civil Construction, and Electric Construction tasks within those respective project phases, and is managed as part of PG&E's material sourcing contingent on applicable material lead times. It is not tracked explicitly in the Subproject Management Template but is aligned with the latest date of the Permitting, Land Acquisition, and Environmental milestones.

c. Controls to Maintain Adherence to Schedules (EUP Guidelines Section 2.5.1(c))

PG&E currently employs a structured change control process and Portfolio Management Framework to manage schedule risk within our Undergrounding Program. We establish annual undergrounding mileage and risk reduction targets and actively manage schedule risk to achieve these program objectives. We will continue the processes and controls described below for our EUP.

To support schedule reliability, we develop an Annual Undergrounding Portfolio that consists of both committed miles and reserve miles. Committed miles comprise scoped Projects and Subprojects that collectively represent the planned undergrounding mileage in a given year (the Annual Project Portfolio). Reserve miles consist of additional scoped Subprojects that may be incorporated into the Annual Project Portfolio if a committed Subproject is determined, through the change control process, to be at risk of missing its scheduled energization date. Underground miles are considered "complete" only upon completion of the following work: (1) energization of new assets, (2) de-energization of existing assets where applicable, and (3) successful quality assurance passage. This Portfolio structure allows PG&E to maintain progress toward annual program targets despite individual project-level schedule variability.

After Project selection and scoping, PG&E establishes a baseline milestone schedule for each Project and Subproject. The baseline milestone schedule includes planned dates for four key activities needed to achieve Subproject completion (i.e., energization of newly installed assets): (1) estimating, (2) dependencies (e.g., permitting), (3) civil construction, and (4) electric construction. Project performance is managed against these milestones throughout execution.

Any potential impacts to the scheduled electrification date are tracked through PG&E's change control process to ensure continued alignment with program-level targets. If a PG&E project manager identifies a risk to a scheduled milestone date, the project manager evaluates the downstream impacts to the project and implements a

recovery plan to mitigate the potential delays. Common strategies for reducing potential schedule delays may include reallocating or adding resources, extending work hours, identifying alternative resources to relieve constraints, resequencing activities, or performing work in parallel to compress schedules.

In addition, PG&E may also address schedule risks by modifying project designs or subdividing Projects into smaller components to improve constructability and schedule performance. Through these controls, PG&E actively manages schedule risk at both the Subproject, Project, and Portfolio levels to maintain adherence to approved schedules, achieving annual program objectives.

2. Workforce Development Plan (EUP Guidelines Section 2.5.2)

Section 8388.5(c)(5) requires the EUP to include a "plan for utility and contractor workforce development." To fulfill this component, the EUP must contain a description of how the Large Electrical Corporation will successfully secure the resources required to implement the EUP for the full 10 years. Some examples include:

a. A list of the job classifications;

b. Annual EUP workforce targets;

c. A description for workforce training, recruitment, and retention;

d. A description of constraints and strategy for addressing those constraints; and

e. A description of the potential impacts that EUP implementation could have on traditional safety and reliability related projects and programs that rely on the same field personnel.

PG&E developed a plan for utility and contractor workforce development to successfully secure resources to implement our EUP. By executing on this plan, PG&E will have sufficient internal and external resources to support the EUP while continuing to meet traditional safety, reliability, and Fire Rebuild obligations, and will continue to manage resource allocation to ensure that critical work across all programs is appropriately prioritized and executed.

PG&E considered the following key elements in developing our EUP workforce plan: (1) the fundamental components of the Undergrounding Program, (2) the resources needed to execute each program

component, and (3) the distribution of resources between internal PG&E team members and external contractors.

The workforce plan reflects the project life-cycle stages, from project identification through scoping, construction, and post-construction activities. PG&E's internal and external resource needs to implement these stages are driven by the number of Undergrounding Projects in development, the number of undergrounding miles planned for construction for any given year, and the forecast for future years. PG&E's resource plan for utility and contractor development is designed to be flexible given the varying number of projects and miles, the location of the miles, the differing project conditions, various work methods, and different efficiency factors.

PG&E worked with Jacobs Solutions Inc., an industry-leading construction and engineering firm with expertise in delivering large-scale projects, to develop an Excel-based resourcing model for our EUP (Workpaper 007 Undergrounding Resource Model).[124] The EUP Resource Model calculates monthly and annual resource requirements, based on undergrounding mileage targets and productivity estimates of the resources critical to implementing the program. The EUP Resource Model provides the estimated resource requirements for more than 30 job classifications, including, for example, project management, estimating, and civil and electric construction.

PG&E's EUP Resource Model uses both historic and forecasted project and workforce data inputs to calculate the projected annual resource needs for the work proposed in the 2028-2037 EUP. Specifically, the EUP Resource Model inputs include:

- Historic Project Information: Mileage and project timeline data from undergrounding work constructed 2022-2025.

[124] Attach. B, WP007 (Undergrounding Resource Model).

- Project Schedule Progression (Workstream Progression):[125] Schedule estimates[126] for construction and non-construction activities (scoping, estimating, and permitting) based on projected undergrounding miles per month and per year (2028-2037) that will progress through the project stages (scoping, design, permitting, and construction).
- Estimated Project Resource Hours: Resource estimates are based on average project size, working days per year, and assumed productivity rates. Productivity rate assumptions reflect civil and electric construction productivity targets and align all labor categories and disciplines, quantifying their expected productivity rate using the Key Performance Indicator (KPI) of Full-Time Equivalent (FTE)/mile.[127] For example, electric construction resource calculations could reflect targets based on number of miles of underground cable pulled per day.

Ultimately, PG&E's EUP Resource Model is a high-level planning model intended to estimate program-level workforce needs based on PG&E's mileage forecast, average project characteristics, and assumed productivity factors. The model relies on historic project data and generalized assumptions and does not reflect final project scope, sequencing, or staffing requirements for individual EUP Projects and Subprojects. The number of internal or external FTE resources generated by the EUP Resource Model is based on information available as of May 2026. Actual workforce needs may vary over time due to changes in authorized program scope, project locations and complexity, permitting timelines, labor availability, contractor market

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[125] The Project Schedule Progress is referred to as Workstream Progression in Attach. B, WP007 (Undergrounding Resource Model).

[126] Schedule estimates for each activity are based on average project lengths and average activity duration for underground projects constructed 2022-2025.

[127] Resource productivity rates standardize productivity measurement across all disciplines supporting the long-term Undergrounding Program, providing a common language and unified approach to measuring productivity. By leveraging the FTE/mile KPI, the resource productivity rates ensure a standardized framework for understanding productivity rates across various labor categories.

conditions, new technologies and other execution factors. PG&E will refine the model's workforce planning assumptions to incorporate post-2025 project productivity and timing data points and to reflect EUP Projects and Subprojects as they are further developed.

a. Job Classifications and EUP Workforce Forecast Estimates (EUP Guidelines Sections 2.5.2 (a) and (b))

As discussed in Chapter 4, Section D.1, an Undergrounding Project is developed over a multi-year period including project readiness (e.g. project scoping, design, estimating, permitting), construction, and project close-out activities (e.g., paving, restoration, and mapping). Table 5-4 provides a summary of the workforce positions responsible for the full lifecycle of an Undergrounding Project. Further information on our estimated annual EUP workforce resource needs (based on the EUP as proposed), at the job classification level, can be found in the EUP Resource Model, on the "Program Wide View" worksheet in Workpaper 007 Undergrounding Resource Model (WP007).[128]

[128] Attach. B, WP007 (Undergrounding Resource Model).

TABLE 5-4:
EUP WORKFORCE POSITIONS

Line No.	Resource Type	Description
1	Project Management	Project Management team members consisting of Senior Project Managers, Junior Project Managers, and Project Controls Analysts.
2	Scoping	Scoping professionals consisting of the PG&E Scoping Lead/Project Manager, Grid Design Team, Construction Managers, Associate Distribution Engineer (ADE)/Estimating Support, PG&E Subject Matter Experts, and Administrative Support.
3	Estimating	Estimating team members consisting of Estimators, ADEs, and Civil Engineers.
4	Customer Outreach	Customer Outreach representatives supporting customer engagement.
5	Encroachment	Specialists consisting of Permit Facilitators, Traffic Engineers, and Agency Liaisons.
6	Land	Land team members consisting of Surveyors (Land, Field, Laser Illuminated Detection and Ranging (LiDAR), and Boundary), Utility Locators, Caltrans Permit Specialists and Project Managers, Land Agents, Right-of-Way (ROW) Agents
7	Environmental	Environmental team members consisting of Land Planning Analysts, Land Planners, Biologists, Cultural Resource Specialists, Environmental Field Specialists, Water Quality Specialists, GIS Specialists, Environmental Inspectors, Compliance Specialists, and Sample Coordinator.
8	Construction Management	Construction Managers, Civil Inspectors, and Electrical Inspectors.
9	Civil Construction	Civil Construction team members consisting of Foremen, Backhoe Operators, Construction Operators, and Utility Workers.
10	Electric Construction	Electric Construction team members consisting of Foremen, Journeyman Linemen, and Groundmen/Apprentice.
11	Post-Construction	Post construction specialists consisting of Clerical resources and Senior Mapping Technicians.

b. Workforce Training, Recruiting and Retention (EUP Guidelines Section 2.5.2(c))

A key requirement for meeting EUP resource needs is to recruit and hire resources with the right qualifications and further develop their qualifications through training and on-the-job performance assessments. In addition, PG&E contracts with third parties who have the necessary

qualifications and skills for undergrounding work. We will continue to build on the recruiting and hiring, training, and third-party contracting efforts described below to deliver on our EUP commitments.

As shown in Table 5-4, PG&E has identified workforce positions for team members working on the delivery and execution of the work proposed in the EUP. For each of the identified positions, PG&E defines the minimum required qualifications and special certifications to establish a well-qualified workforce. The required qualifications for the different workforce positions vary but include items such as minimum education requirements; relevant experience in areas such as project management, project controls, electrical, mechanical or civil engineering, estimating, design, distribution planning, land surveying, and traffic control; and special certifications or qualifications such as Project Management Professional, Professional Engineer, licensed California Land Surveyor, Journeyman Lineman, and American Traffic Safety Services Association certification.

PG&E will use the EUP's 10-year workforce plan to balance existing internal staff, hiring additional resources and external resources (e.g., staff augmentation, contractors, consultants, etc.) and continue to develop the workforce. PG&E's recruiting team utilizes the FTE and resource estimates from the EUP Resource Model and identifies internal and external resourcing strategies. The team also partners with PG&E's Labor Relations experts to ensure that workforce planning adheres to applicable labor agreement guidelines.

PG&E's internal resourcing strategy focuses on finding qualified resources to fill open positions, when and where they are needed. PG&E's internal recruiting team works with Undergrounding Program management team to develop a plan for identifying and hiring the right resources. PG&E's recruiting team may work with community colleges, universities, trade schools, career sites, trade associations, and job boards to locate interested and qualified resources.

In addition to traditional recruiting methods, PG&E established the PowerPathway program to offer training to individuals interested in entry-level careers at PG&E and the construction-energy industry.

PowerPathway is a nationally recognized workforce development model that works with community organizations, schools, and local governments to develop a sustainable pipeline of candidates for PG&E and the industry. More than 1,300 students have graduated from this program from 2008 through 2025. Many PowerPathway students come from communities impacted by wildfires and where Undergrounding Projects are occurring. In addition, the program focuses on recruiting military veterans and individuals who are currently unemployed.

The PowerPathway training program is a free multi-week training that includes both classroom and hands-on learning. Since 2017, approximately 86 percent of the program graduates have been hired by PG&E or within the utility industry, providing an opportunity for often disadvantaged community members to build a career.

As an example of PowerPathway's relevance to the proposed EUP, in June 2023, PowerPathway held an all-military veteran undergrounding training program. To ensure our workforce is representative of the communities we serve, all of the participants lived within 50 miles of a work headquarters in the Sacramento North Valley area. Upon graduating, all 20 military veterans were placed in careers at PG&E supporting Undergrounding Projects; of this number eight were construction utility workers and 12 were traffic control professionals.

PG&E intends to leverage the PowerPathway program to fill civil and electrical construction crew needs to support the proposed EUP. We expect the program to expand our civil and electrical crews who live and work in our hometowns and help create a pipeline for leadership and journey-level positions that are difficult to fill. After graduating PowerPathways, these individuals can be promoted based on their career interests, location, and the needs of the program, via progression tracks that are already in place for the Undergrounding Program.

1) Workforce Training

Depending on the role, PG&E employees working on the EUP may receive additional technical training, certifications, and undergo qualification testing for various critical skills that may be required for their classification and level of progression. This section

summarizes three core training resources applicable to the Undergrounding Program.

First, PG&E Academy develops and delivers technical, safety, and other training that helps to maintain a skilled, safe, and qualified workforce. The Academy Electric Technical School provides training courses on a wide range of technical topics, including planning, engineering, maintenance, construction, equipment operation, asset management, energy restoration, and emergency response.

Second, PG&E offers apprenticeships focused on Electric Operations including the Line Worker, Cable Splicer, Electrician, Electrician Technician, and Distribution System Operator programs. Employees are assigned training in the Learning Management System (LMS) using a combination of methods depending on the design of the training program. For apprenticeship programs, the course curriculum is mapped out in the LMS and the employee is enrolled as required for their classification and current level of progression. Non-apprentice related trainings are reviewed and approved by the Training Governance Committee and are then assigned to employees based on job profile in accordance with our Training Profiles Standard.

Third, PG&E has multiple courses open to our General Construction Civil Undergrounding team focused on performing high quality work safely. The courses can include training on three-way communication, human performance, map reading, electric and gas safety, and serious injury and fatality prevention.

2) Third-Party Contracting

PG&E developed a multi-year third-party contractor sourcing strategy to support our Undergrounding Program resource needs and meet the EUP mileage, safety, and cost targets.

As of the time of submitting this plan, PG&E has Master Services Agreements (MSA) in place with nine undergrounding contractors. PG&E currently has contract resourcing capacity in-place to fulfill proposed mileage targets through at least 2029 and

is continuing to develop and test new undergrounding sourcing approaches to support future program targets.[129] These approaches include:

- Adjusting the size of the contractor pool over the life of the program to manage internal and external workforce resources, while maintaining the flexibility to scale as needed;
- Preparing a pipeline of construction-ready work (e.g., designed and permitted projects) to facilitate bundling work for competitive bids, such as lump sum or direct negotiation—which can drive cost reductions;
- Allocating select underground miles to test and validate new suppliers to ensure a qualified, competitive pool of contractors is available to support all the workstreams of the program; thus creating opportunities for diverse, small, and local businesses as well as opportunities to benefit from unique skill sets or specializations of particular vendors; and
- Sourcing multi-year MSAs with flexible delivery models (e.g., direct negotiation, lump sum, unit pricing and quick bid).

3) Employee and Contractor Retention

PG&E's ability to execute the EUP over the full ten-year period depends on developing and retaining an experienced employee and contractor workforce. Approval of a ten-year EUP will strengthen PG&E's ability to recruit, develop and retain the skilled, sizeable and innovative workforce needed to deliver the program. PG&E's retention approach is designed to support safe, efficient execution and reduce turnover-related schedule and cost risk by promoting continuity of work, maintaining required qualifications, and providing career development opportunities.

PG&E supports employee retention through our long-term workforce planning initiatives; established progression tracks for key classifications (including entry-to-journey pathways where applicable); and ongoing training and qualification maintenance

[129] The number of MSA holders may change based on performance and cost.

through PG&E's Academy, apprenticeship programs, and role-specific training (including safety-focused programs). PG&E also uses recruiting and pipeline programs such as PowerPathway to connect entry-level hiring to longer-term careers, which can support retention by improving job readiness and providing clear advancement opportunities. PG&E provides market-based pay and health and wellness benefits to attract and retain a qualified workforce.

PG&E seeks to promote continuity of contractors, including suppliers, crews, and individuals by providing long-term visibility into workload, using contracting structures intended to support stable resourcing, and applying clear safety, quality, and performance expectations as the basis for continued engagement. These practices are intended to help ensure sufficient resources over time while maintaining accountability for safety and performance. PG&E supports contractor retention by developing a multi-year sourcing strategy and using MSA to provide continuity of work and resourcing capacity. PG&E sets clear expectations for safety, required qualifications, quality, and schedule performance, and uses those expectations to support accountability and continued engagement of high-performing contractors. PG&E also seeks to reduce contractor churn by improving work bundling and providing multi-year visibility into the workplan (including moving toward a more levelized long-term workplan where feasible) to help contractors maintain experienced crews and invest in equipment and training needed to efficiently execute undergrounding work.

c. Description of and Strategy for Addressing Resource Constraints (EUP Guidelines Section 2.5.2(d))

Given the complexities of an Undergrounding Program and the typical shifts in individual project schedules, there are times when more resources are needed to complete scheduled work than were previously identified. In the event additional resources are needed, solutions can include extending working days/hours of construction crews, reassigning work amongst construction vendors and/or PG&E crews, adding

additional construction vendors for short-term needs via Standalone Agreements, and adjusting project schedules.

d. Managing Potential Impacts Among the EUP and Traditional Safety and Reliability Projects (EUP Guidelines Section 2.5.2(e))

Traditional safety and reliability projects and programs include work such as vegetation management, system inspections, pole replacement and other electric maintenance activities, that rely primarily on electric and vegetation management crews and less on civil construction crews. PG&E's EUP work will be executed by civil construction crews who typically perform 80 percent of the work and electric crews who perform approximately 20 percent of the work. This is because the longest duration undergrounding construction work is related to the civil substructure work, i.e., digging the trenches and installing conduit into which the electric lines will be pulled. Given the reliance on different crews, it is unlikely that the most frequently used field personnel supporting the EUP will represent a resource constraint for routine safety and reliability work.

At times, PG&E may need to respond to wildfire events that require activities in Fire Rebuild Areas. Fire Rebuild work is prioritized to support customer restoration and public safety and may require the temporary reallocation of certain civil construction and electric resources, including resources that also support the EUP. When such conditions arise, PG&E may shift resources to prioritize Fire Rebuild activities. PG&E manages these potential overlaps through a structured change control process and Portfolio management framework. As described in Section C.1 above, PG&E actively manages the EUP Project Portfolio, including the use of committed and reserve projects, and change control processes to mitigate schedule risks and maintain progress toward annual program targets. To the extent resource constraints arise due to Fire Rebuild or other priorities, PG&E will adjust project sequencing, deploy reserve projects, and/or supplement resources through additional hiring or contracting, as appropriate.

Based on current staffing levels and contracting arrangements, PG&E has sufficient internal and external resources to support the EUP

while continuing to meet traditional safety, reliability, and Fire Rebuild obligations, and will continue to manage resource allocation to ensure that critical work across all programs is appropriately prioritized and executed.

3. Costs and Benefits (EUP Guidelines Section 2.5.3)

Section 8388.5(c)(6) requires the EUP to include "an evaluation of project costs, projected economic benefits over the life of the assets, and any cost containment assumptions, including the economies of scale necessary to reduce wildfire risk and mitigation costs and establish a sustainable supply chain." To fulfill this component, the EUP must contain a narrative for each of the following:

a. Evaluation of project costs;

b. Projected economic benefits over the life of the assets;

c. Cost containment assumptions (including economies of scale necessary to reduce wildfire risk and mitigation costs); and

d. Strategies for achieving a sustainable supply chain and the economies of scale necessary to reduce costs over time.

a. Evaluation of Project Costs (EUP Guidelines Section 2.5.3(a))

1) Mitigation Alternative BCR Analysis

PG&E uses our WBCA model to evaluate project costs and benefits for the Alternative Mitigations and Additional Comparisons that we analyze in Screen 2 and Screen 3. The WBCA model methodology, key inputs and outputs are detailed in Chapter 7, Section D.6. We use the WBCA model to conduct the BCR analysis to assess Alternative Mitigations and Additional Comparisons in Screen 2 that are listed below and further described in Chapter 3, Section D.2. See Chapter 3, Section D.2 and Table 3-9 for a description of the comparison types described below.

1) <u>100 percent Underground</u>
2) <u>Alternative Mitigation 1</u>
3) <u>Alternative Mitigation 2</u>
4) <u>Additional Comparison</u>

The BCR values for Alternative Mitigations and Additional Comparisons are further refined in Screen 3. In Screen 3, PG&E generates BCRs for the "Project as Scoped" and the

"Undergrounding as Scoped" mitigation scenarios. The Project as Scoped is all work in the final project design including all undergrounding and non-undergrounding portions of the project. The Undergrounding as Scoped includes only the portion of the Circuit Segment that will be undergrounded.

The cost and benefit inputs into the WBCA are described below. For each Circuit Segment, the WBCA provides the forecasted cost to build and maintain each of the Alternative Mitigations and Additional Comparisons and an estimated BCR.

The BCR is PG&E's first but not only consideration when selecting a system hardening mitigation. The California Public Utilities Commission (CPUC or Commission) has stated that "the utility is not bound to select its Mitigation strategy based solely on the Cost-Benefit Ratios produced by the Cost-Benefit Approach."[130] Consistent with this direction, PG&E uses the BCR and other factors to select Alternative Mitigations and Additional Comparisons. PG&E considers multiple factors in selecting alternatives because an over-emphasis on the BCR may devalue projects that are both high cost and high benefit. The BCR does not reflect the magnitude of benefits and value of permanent risk mitigation and, when used as the sole criteria, may result in situations where significant risk is permanently left on the system. As a hypothetical example, Project A could have total risk reduction benefits of $10 million with a lifetime cost of $5 million, while Project B could have a total risk reduction benefit of $1 million with a lifetime cost of $0.5 million. Both Projects would have a BCR of 2, but Project A has the highest magnitude of benefits. PG&E's Screen 3 analysis considers the full range of benefits, including mitigation of tree strike risks, reliability risks created by operational mitigations, and ingress/egress concerns.[131] A utility must be able to consider multiple factors

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130 Decision (D.) 22-12-027, Appendix A, p. A-16, Row 26.

131 Per ACI PGE-26B-07, the process for consideration of these risks may change when PG&E adopts WDRM v5 or makes other changes to our risk modeling approach in future.

when selecting a mitigation and not be limited in its decision-making to just a single factor.

2) Calculating BCRs

The BCR is the ratio of benefits to costs. It is the present value of the lifetime benefits of a project divided by the present value of the lifetime costs. The BCR measures how much benefit is gained per dollar spent. A BCR greater than 1.0, or a negative BCR, indicates that the benefits of a project outweigh the costs. The BCR is calculated by dividing Lifetime Benefit by the Lifetime Costs for each Alternative Mitigation and Additional Comparisons.[132]

$$\textbf{Formula:}\ \frac{(NPV\ Monetized\ Risk\ Avoidance)}{(Lifetime\ Costs)} = Benefit\ Cost\ Ratio_m$$

A more detailed explanation of the WBCA model methodology and calculations is provided in Workpaper 006 WBCA Whitepaper (WP006).[133]

3) Project Cost Inputs into the WBCA

PG&E uses the WBCA model to estimate the present value of capital costs over the life of the asset for each Alternative Mitigation and Additional Comparison 1. Total project costs consist of: (1) the capital costs to construct the project (Initial Capital Spend); (2) the capital and expense amounts to operate and maintain the asset relative to the existing baseline assets (net operations and maintenance (O&M) costs); (3) vegetation management costs (Lifetime Vegetation Management Expense); (4) project financing costs; and (5) a climate adjustment factor. The basis and values for each of these project costs are used as an input into the WBCA model. PG&E proposes to review the validity of these input values at the time of the WBCA model update (see Chapter 8 Section C).

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132 This BCR methodology is consistent with the methodology developed in the Commission's Risk-Based Decision-Making Framework (RDF) Rulemaking (R.) 20-07-013 adopted in D.22-12-027.

133 Attach. B, WP006 (WBCA Whitepaper).

4) Initial Capital Spend

Initial capital spend consists of the installation costs to implement a system hardening project. Cost types include: scoping and surveying; project design and estimating; pre-construction preparations such as ordering materials, acquiring permits and land rights, and conducting any required vegetation work; construction activities needed to install and energize new equipment; and project close-out work including paving, removal of prior overhead electric equipment, site restoration, mapping, and finalizing project documentation. The capital costs used for the WBCA are informed by historic costs, Circuit Segment assumptions and forecast efficiencies. (See WP006 WBCA Whitepaper for further detail.)[134]

5) Lifetime Capital and Expense O&M Spend

O&M costs are needed to operate and maintain an asset over its lifetime. The categories of O&M costs that are included in PG&E's project cost analysis are as follows:

- Patrols and Inspections: PG&E regularly inspects our overhead and underground electric facilities to proactively identify areas of deterioration and degradation, including any pending failures of asset components and issues caused by outside forces or third-party contact that may create unsafe conditions, outages, or lead to an ignition.
- Maintenance and Repair: Maintenance programs consist of expense and capital repair/replacement work to address overhead maintenance conditions identified by PG&E's patrol and inspection process. PG&E uses a risk-informed prioritization approach to address the highest risk issues on our system. Maintenance tags are assigned a priority based on the potential safety impact, in accordance with CPUC General Order (GO) requirements (e.g., GO 95 and GO 128). PG&E's maintenance of our Electric Distribution facilities improves public safety, employee safety, and reliability. Almost all the

[134] Attach. B, WP006 (WBCA Whitepaper).

maintenance activities involve facilities which, if they failed, could potentially disrupt or degrade service, cause an ignition or pose a risk to the public or PG&E workers. Maintenance of Electric Distribution facilities is also required for regulatory compliance.

- EPSS: Distribution Control Center operators (Operators) receive daily instructions to enable and/or disable EPSS based on Wildfire Risk for the day. When outages occur on PG&E distribution circuits, the entire Circuit Segment that experienced the outage must be patrolled before power can be restored to customers. A patrol involves a visual examination of applicable overhead facilities to identify obvious structural problems and hazards that may have caused the outage and a possible ignition if not cleared prior to reenergization. Post-outage patrols on EPSS-enabled circuits ensures the system is safe to facilitate restoration of the outage as quickly as possible. In addition to enabling EPSS settings, the Operators are responsible for monitoring outages when EPSS settings are activated and coordinating with field personnel and engineering on the safe patrol and restoration of circuits.
- Public Safety Power Shutoff (PSPS): PSPS event costs consist of the cost for activities directly associated with PG&E's proactive de-energization of overhead electric distribution lines following a determination of weather-related imminent threats to power line assets and increased risk of catastrophic wildfire. This includes the sequence of activities associated with activating the Emergency Operations Center (EOC), sending customer and agency notifications, de-energizing power lines to reduce the risk of those lines igniting a wildfire during a weather-related event, patrolling the deenergized overhead lines to ensure there are no hazards on the line that could have

caused an outage or ignition, and re-energizing the lines once it is safe to do so.[135]

- Routine and Major Emergency: Electric emergencies are created when outages occur and require immediate response by PG&E to restore customer service and protect the community from potential safety hazards. Emergency outages can range from Routine Emergencies resulting from equipment failures and day-to-day weather conditions to Major and Catastrophic Emergencies arising from major storms or natural disasters. PG&E's response to electric emergencies is a fundamental part of operating an electric distribution system and is subject to the requirements of GO 166. PG&E prepares an electric emergency response plan that defines staffing levels, roles and responsibilities, emergency incident assessment guidelines, and communication plans. The response plan supports PG&E's activation of emergency centers and mobilization of crews and other resources to respond to routine and major emergencies. Since underground lines are largely protected from weather-related hazards we forecast significantly reduced emergency response activities needed on underground system throughout the life of the asset.

O&M costs are expressed as a unit cost specific to the activity type and vary depending on the mitigation. For example, PG&E will not incur EPSS-related O&M costs where lines are underground but will continue to incur them where covered conductor is installed. PG&E also does not incur PSPS-related operational costs in areas where lines are undergrounded.

To develop the O&M costs for each mitigation, PG&E evaluated Maintenance Activity Type (MAT) cost forecasts in our 2023 General

[135] Because underground electric distribution lines are not subject to the same weather-related ignition risk as overhead lines, PSPS events are not applicable to areas where lines have been undergrounded. As a result, PG&E does not include PSPS-related operational and response costs for underground segments. This includes the elimination of costs associated with EOC activation, customer and agency notifications, de-energization, patrols of deenergized lines, and re-energization/restoration activities.

Rate Case (GRC).[136] For example, for overhead maintenance and repair activities, PG&E identified 20 different individual work categories from the Electric Distribution forecast[137] that are attributable to some or all of the mitigations. These include but are not limited to pole replacement, distribution equipment maintenance and replacement, overhead conductor replacement, and expulsion fuse replacement. We calculated an average cost per overhead circuit mile for each cost type (MAT) starting with the imputed adopted costs, with escalation, from PG&E's 2023-2026 GRC,[138] and divided that amount by the number of overhead circuit miles in our system to determine the average cost per mile for each MAT. In some cases, where appropriate, PG&E refined the average calculation to provide more location-specific O&M values if possible. For example, for the outage and emergency costs, the cost estimates were further refined based on historic county-level spend. Over the life of the assets, undergrounding is expected to avoid $1.5 million in O&M spend per mile. These total forested avoided costs include the lifetime vegetation management expenses described below.

6) Lifetime Vegetation Management Expense

Lifetime vegetation management expense refers to the expense amounts required to maintain vegetation clearances around distribution lines as informed by GO 95, Rule 35, Appendix E. PG&E will not incur on-going vegetation management costs where primary overhead lines are relocated underground. However, where PG&E installs covered conductor, we will continue to incur Vegetation Management costs.

Vegetation Management consists of: (1) routine regulatory compliance work that includes performing annual patrols of vegetation in proximity to PG&E's overhead electric distribution lines

[136] Application (A.) 21-06-021.

[137] A.21-06-021, Exhibit PG&E-4.

[138] D.23-11-069.

and performing any prescribed tree work (e.g., trimming, pruning, removal); (2) hazard inspections conducted in high Wildfire Risk areas; (3) pole clearing activities that include the removal/clearing of vegetation around distribution poles to maintain firebreaks; and (4) managing wood material by chipping, relocating, or hauling away wood from Vegetation Management work. The Vegetation Management work is location-specific. The expected avoided vegetation management costs range from $17,000 to $3,600,000 of lifetime costs per mile.

As discussed in Chapter 3, Sections D.2 and D.3.a.6, Projects with significant lifetime O&M savings can occasionally result in a circumstance where the lifetime NPV of the Project costs (capital installation costs plus lifetime O&M) is actually negative, making the Project a net positive investment on just expenditures alone, without even considering benefits. While rare, these cases do emphasize why the BCR cannot be the exclusive decision-making criteria. A full understanding of the Project as well as BCR factors must be considered to select a system hardening mitigation.

7) Financing Costs

The WBCA also incorporates certain financing elements to calculate annual cash flows that enable a comparison of annual costs and benefits by mitigation.

- Asset Life: The asset life period determines how many years of O&M costs and expected benefits are included in the BCR calculations. The WBCA model uses the Overhead and Underground Asset Life in PG&E's 2023 GRC decision[139] with a benefit life of 55 years for underground assets and 48 years for overhead assets.
- Present Value Rate of Return (PVRR): PVRR represents the present value of revenue that must be collected from customers to pay for the costs incurred on a Project, including a fair and

[139] D.23-11-069, p. 676, Table 10-E.

reasonable rate of return on investment, over the life of the Project.

- Discount Rates: In compliance with the Risk-Based Decision-Making Framework Phase (RDF) II Decision, PG&E shows the numerator and denominator of the BCR as present values.[140] In the RDF Phase III Decision, the Commission directed utilities to use three different discount rates in their BCR calculations but allowed utilities to identify the value they prefer to use in their decision-making.[141] PG&E calculates three different BCRs for each Project using the three discount rates required by the CPUC and uses the After-Tax Weighted Average Cost of Capital (ATWACC)[142] as the basis for our decision-making. The stream of future costs and benefits in both the numerator and denominator of the BCR calculation are discounted at the same rate.[143]
- Real Discount Rates: The real discount rate is used for calculation of the net present value of risk reduction benefits and the lifetime costs for each mitigation considered.
- Inflation Rates: PG&E is using the average annual Consumer Price Index for All Urban Consumers (CPI-U) growth forecast from the Long-Term Budget Outlook, published by the Congressional Budget Office.[144]

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[140] See D.22-12-027, Appendix A, p. A-15, No. 25.

[141] See D.24-05-064, pp. 102-103 and 122, Conclusion of Law No. 31.

[142] The ATWACC used in the WBCA model is based on PG&E's cost of capital authorized in D.24-10-008.

[143] R.20-07-013, The Utility Reform Network White Paper On Phase 3, Workshop 5 Discount Rates (Oct. 31, 2023), which corroborates the applicability of a single discount rate equal to WACC.

[144] Congressional Budget Office, The 2023 Long-Term Budget Outlook (June 2023), Long-Term Economic Projections that support Table 3-1, available at: <https://www.cbo.gov/system/files/2023-06/59014-LTBO.pdf> (accessed May 11, 2026). PG&E is using this consumer data in its risk modeling only as it is publicly available and has a long-term projections. PG&E does not use the CPI-U data for cost recovery purpose as it is not based on utility costs.

8) Cost-Benefit Approach (CBA) Reliability Risk Conversion

The CBA Reliability Conversion in the WBCA is a Cost per Customer Minutes Interrupted (CMI) output from the Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) Calculator version 2 used to determine a standard dollar valuation of electric reliability risk for the Reliability Attribute, with the main output section producing discrete results for residential and non-residential customer classes.[145]

9) Climate Assumptions

PG&E includes two climate-related impacts in its WBCA.

- Fire Weather Index (FWI): The FWI variable measures the projected annual number of days per circuit segment that exceed the historical 95th percentile FWI value at that segment. The 95th percentile threshold is defined using a 20-year historical baseline centered on 2004 (1995-2014), a reference period commonly used in climate analyses. Future exceedance counts are derived from climate projections[146] averaged over 20-year windows centered on 2030, 2050, and 2080. The FWI is a generalized measure of fire potential that incorporates both fuel aridity and fire weather conditions, regardless of fuel type or abundance. It is calculated using daily maximum temperature, minimum relative humidity, average wind speed, and precipitation. Changes in the frequency of high-FWI days impact the probability that an ignition occurs during Red Flag Warning (RFW) conditions. Since ignitions associated with RFW conditions have higher per-event consequences than non-RFW ignitions, a risk multiplier for RFW outcomes is calculated at the Circuit Segment level. This multiplier scales proportionally with increases in annual days exceeding the historical 95th percentile FWI.

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[145] A.24-05-008, Exhibit (PG&E-2), p. 2-12, Section C.5.b.

[146] Projections use the ensemble average of Wildfire Risk simulations driven by eight downscaled Global Climate Models under SSP3-7.0 scenario.

- Heat Day Analysis: Based on historical experience, equipment failure rates increase roughly proportionally with the frequency of continued heat events. These events are defined as periods of three consecutive days exceeding 92°F where both daily highs and lows surpass their respective 10-year averages. A heat-based equipment-failure frequency multiplier is calculated at the Circuit Segment level to capture climate-driven changes in sustained heat exposure.

Climate assumptions also impact EPSS and PSPS programs. The frequency of events in these outage programs is likely to increase as environmental conditions are conducive to wildfire increase.

b. Projected Economic Benefits over the Life of the Assets (EUP Guidelines Section 2.5.3(b))

1) Benefits Included in the BCR Calculation

The benefits included in BCR calculation are described below and are explained in greater detail in Chapter 7, Section D.6 and in the WBCA Whitepaper.[147]

- Wildfire Benefit: The wildfire benefit quantifies the Wildfire Risk reduced by calculating the existing Wildfire Risk on the system (assuming existing infrastructure and PSPS is present) associated with each Circuit Segment before a particular mitigation is implemented. The wildfire benefit takes into account changes over time due to climate change from 2028-2082. (See Chapter 7, Sections G.4.c and G.6.e for details regarding the climate change factors.)
- Public Safety Benefit: The public safety benefit quantifies the non-wildfire safety impacts that a Circuit Segment poses to the public. The main component of the public safety benefit is referred to as the public contact with intact energized electric equipment (PCEEE) which is the risk of serious injury or fatality to members of the public or contractors resulting from

[147] Attach. B, WP006 (WBCA Whitepaper).

interaction with intact, energized electric assets, where the event does not originate from asset failure. We refer to the public safety benefit as "Safety Risk Reduction."

- Reliability Benefits: Reliability benefits quantify the reduction in customer service interruptions associated with implementing a mitigation. CMI measures the total amount of time a PG&E customer's electricity access is interrupted. CMI is a cumulative sum of the interruption time for all affected customers and is calculated at the Circuit Segment level. Generally, to calculate the reliability benefits, the total CMI is multiplied by the Value of Service (VoS) per minute from the ICE calculator. In the WBCA, reliability benefits are composed of three distinct components:
  - Baseline Reliability Benefit: The baseline reliability benefit reflects the reduction in CMI under normal operating conditions, excluding interruptions associated with EPSS and PSPS programs. This component captures improvements in system performance resulting from reduced outage frequency and duration due to the mitigation.
  - EPSS Benefit: The EPSS benefit quantifies the reduction in outages attributable to EPSS exposure for each Circuit Segment when a particular mitigation is implemented. EPSS risk is a function of CMI and reflects only those customer minutes interrupted attributable to EPSS. Calculation of this benefit is described in Chapter 7, Section D 3.
  - PSPS Benefit: The PSPS benefit quantifies the reduction in PSPS exposure for each Circuit Segment when a particular mitigation is implemented. PSPS risk is a function of CMI and reflects only customer minutes interrupted attributable to PSPS. Calculation of this benefit is described in Chapter 7, Section D 4.

2) Mitigation Effectiveness

Project Variable Modifiers (PVM) are used in the WBCA to determine the effectiveness and therefore the resulting benefits (i.e., risk reduced) for each mitigation. (See Chapter 7, Section K, PVMs, for the details of how these values are calculated.)

c. Cost Containment Strategies Including Economies of Scale Necessary to Reduce Wildfire Risk and Mitigation Costs (EUP Guidelines Section 2.5.3(c))

Managing undergrounding costs is an integral part of PG&E's Undergrounding Program. Our cost containment strategy includes two key components: (1) sourcing strategies; and (2) work execution strategies. By implementing many of the sourcing and work execution strategies detailed below, PG&E has already reduced the unit cost of undergrounding by more than $1 million per mile. As certainty of long-term undergrounding plans increases through approval of our EUP, PG&E expects to be able to generate greater economies of scale with internal crews, contractors, materials suppliers, designers and others. We anticipate continuing to drive cost savings over the 10-year period, saving approximately ~~$220,000~~$150,000 per mile by 2037. When scaled across the thousands of miles being proposed in the EUP, these efficiencies are estimated to reduce unit costs by ~~$746~~$496 million over the 10-year period, before escalation. (See Target/Timeline Table for the declining annual unit cost targets over the EUP period.)[148]

Specific cost containment strategies are described in more detail below.

1) Sourcing Strategies to Reduce Program Costs

PG&E is testing and validating how different sourcing approaches can reduce undergrounding costs. As noted above, approval of the EUP will increase certainty in the volume of undergrounding work over the 10-year EUP:

[148] The Target / Timeline Table is provided in Progress Report 0 as Table A-2 (in Attach. A), and as required in EUP Guidelines Section 2.3.1.k, PG&E has included an excel workbook in Attach. B, WP002 (EUP Target / Timeline Table).

- Competitively Bid Lump Sum Fixed Price: Competitively-bid lump sum fixed price sourcing strategies provide cost savings opportunities for a variety of reasons. For instance, in comparison to unit price sourcing strategies, lump sum fixed price sourcing strategies shift the potential risk of cost increases occurring during construction onto the contractor as opposed to the ratepayer. Additionally, by soliciting multiple offers (i.e. competitively bidding), PG&E can compare costs and ensure they receive the best value. In 2025, the program achieved approximately 15 percent cost savings by leveraging this pricing and delivery model. Competition encourages contractors to offer their most competitive pricing and creates an environment where a contractor with unique experience, skills or tools to offer the lowest price and win the work. It is worth noting that lump sum fixed price contracts require the timely development of construction ready work to give bidders more certainty in the scope of work prior to taking on the risk of cost increase that may materialize during construction. The certainty provided by an approved 10-year EUP enhances PG&E's ability to prepare construction-ready work and encourages contractors to invest in tools, training and experience development to continually execute work more efficiently.
- Directly Negotiated Fixed Price: Negotiated lump sum fixed price sourcing strategies offer similar cost savings advantages as competitively bid lump sum fixed price contracts in that the fixed price component of the contract shifts potential cost increases during construction onto contractors. However, directly negotiated lump sum fixed price contracts do not offer the potential for additional savings from competition. For this reason, directly negotiated lump sum fixed price contracts are used opportunistically with contractors identified through the competitive lump sum process to further reduce the price with crews already mobilized in/near the location.

- Design Build – Engineering, Procurement, Construction (EPC): This sourcing strategy involves selecting one supplier to design, procure materials, and construct a Project. This approach may allow a contractor to harvest efficiencies from the integration of design and construction resource groups to lower the overall Project cost. Typically, this methodology also places the risk of scope changes and many other unexpected conditions on the supplier to the benefit of PG&E and our customers. PG&E is currently piloting this strategy on several Projects.
- Production Paving: PG&E implemented a new paving contracting approach in 2025 to leverage economies of scale with other PG&E paving and restoration work. Since implementing this approach, PG&E has achieved a 30 percent savings in paving costs for Undergrounding Projects.
- Traffic Control: Traffic control is normally subcontracted by the electric and civil construction vendors using rates agreed upon by the construction vendor and the traffic control provider and often includes a markup for these services which PG&E pays as a pass-through cost. PG&E's undergrounding team has piloted an approach in partnership with other PG&E teams to coordinate scheduling, dispatching, and invoicing for Traffic Control services and to leverage new rates negotiated by PG&E's Sourcing team directly with the traffic control providers. This effort has resulted in a 20 percent reduction in cost for traffic control.

As these, and more, sourcing strategies are tested, PG&E will standardize those that generate cost savings while continuing to look for additional opportunities to reduce costs through sourcing.

2) Work Execution Strategies to Reduce Program Costs

PG&E also identified cost savings initiatives aimed at optimizing work execution. These cost savings initiatives can involve updating standards for design and construction, exploring and implementing innovative construction methods, and implementing technological

solutions to reduce the cycle time from initial scoping to completion of construction.

Table 5-5 below lists cost savings initiatives related to work execution that PG&E is currently assessing or implementing. The table details the initiative name, description including Technology Readiness Level (TRL),[149] and how that initiative is driving, or could drive, savings. As the long-term Undergrounding Program progresses, PG&E will continue to look for innovative models and methods to install undergrounding more efficiently.

[149] TRL Scale: TRL 1 – Basic principles observed and reported; TRL 2 – Technology concept formulated; TRL 3 – Experimental proof of concept; TRL 4 – Technology validated in lab; TRL 5 – Technology validated in relevant environment; TRL 6 – Technology demonstrated in relevant environment; TRL 7 – System prototype demonstrated in operational environment; TRL 8 – System complete and qualified; TRL 9 – Actual system proven in operational environment.

TABLE 5-5:
COST SAVINGS INITIATIVES

Line No.	Initiative	Description	Cost Savings Driver
1	Lid Leveling Wedges	Leveling box lids to the surrounding ground in rough terrain often requires more slope than the existing built-in leveling system allows. Much of the civil work for the Undergrounding Program has been in rough terrain without existing viable solutions to level lids with the surroundings. PG&E started to utilize pre-cast solutions for lid leveling in 2025 and they are now available for use on any applicable Projects. Status: TRL 9	The use of precast wedges reduces labor and materials costs of pouring cast-in-place concrete leveling collars at each site.
2	Native Slurry Backfill (NSB)	NSB is a controlled low-strength material (CLSM) comprised of native soil, cement, and water. Excavated, native soil from the trench or site vicinity is used as the soil/aggregate component in the CLSM mixture. Any soil, cement, equipment, and procedure may be used, provided strength and flowability performance criteria are met. Status: TRL 8	The use of NSB makes the handling of soil spoils from trenching more efficient by reducing the number of steps and handoffs. This includes reducing the time waiting for sampling, and elimination of transportation costs and time spent trucking.
3	Optimizing Spoils Mitigation	Spoils management effort to identify opportunities to optimize spoils handling. Our current initiatives include strategically locating spoils recycling sites to reduce trucking and handling costs, and early job stage soil sampling to inform optimal spoils planning. Status: TRL 8	These efforts lead to a reduction in the number of truck loads and distance spoils must be hauled, fewer bottlenecks in the construction process, and less impact on communities from truck traffic.

TABLE 5-5
COST SAVINGS INITIATIVES
(CONTINUED)

Line No.	Initiative	Description	Cost Savings Driver
4	Fluid-free Steerable Boring	PG&E, in collaboration with the EPIC program, is working to assess if fluid-free steerable boring, a new technology, could provide a cost-efficient method compared to the current Horizontal Directional Drilling (HDD) technology which requires expensive disposal of large amounts of liquid spoils (bore gel). The viability of this new technology is likely to be dependent upon factors such as soil conditions and the size of the conduit being installed, and so further investigation is necessary to understand its suitability in PG&E's service territory. Status: TRL 5	If feasible, fluid-free steerable boring could result in cost reductions by eliminating the need to remove, process, and haul liquid boring spoils.
5	Diverse Construction Methods	Identification of construction methods tailored to the unique challenges of each Project—such as location, terrain, and soil conditions—enables more efficient construction. PG&E has implemented innovative equipment, including a single pass plow and single pass trencher. When used in the appropriate scenarios, these methods significantly reduce trenching time and improve productivity. There can be limitations to the available quantity of this equipment, and the establishment of the 10-Year Plan allows for scaling of this innovative equipment and gives vendors the confidence to purchase these expensive but efficient construction tools. Status: TRL 8	By utilizing diverse and innovative construction methods that are specifically selected based on a project's unique challenges and terrain, we can ensure projects are constructed in the most efficient manner.

TABLE 5-5
COST SAVINGS INITIATIVES
(CONTINUED)

Line No.	Initiative	Description	Cost Savings Driver
6	New Electric Concrete Enclosure Designs with Knock-Outs	PG&E has been coordinating with an external vendor to improve the design for frequently-used electric concrete enclosure boxes by adding upper knockouts to allow for reduced soil excavation and improved safety. Status: Status: TRL 9	The improved design saves costs by reducing necessary labor, soil excavation and the need to remove, process, and haul spoils, supporting faster installation.
7	Enclosure Elimination	The enclosure elimination initiative is an underground construction optimization effort focused on reducing or eliminating unnecessary pull enclosures by enabling longer pulls where technically feasible. We leverage improved pull calculations, new fiberglass conduit sweeps, the use of more effective lubricants, and revised enclosure designs to safely extend pull lengths while ensuring a safe, reliable system is being installed. Status: TRL 8	By eliminating unnecessary enclosures, we save costs by reducing material costs, soil excavation, the need to remove, process and haul spoils, and some restoration/paving.
8	Minimum Cover Distribution System (MCDS) and Ground Level Distribution System (GLDS)	MCDS and GLDS are alternative construction methods that we are assessing as potentially quicker and cheaper approaches to underground electric lines in specific locations. These methods involve placing a cable in conduit (encased in a geopolymer composite fill) inside a fire-rated cable tray assembly installed below grade at an approximate burial depth of 10 inches (MCDS), or at ground level (GLDS). Status: TRL 7	These construction methods enable undergrounding in difficult terrains and environmentally sensitive locations and provide the opportunity for time and cost efficiencies.

TABLE 5-5
COST SAVINGS INITIATIVES
(CONTINUED)

Line No.	Initiative	Description	Cost Savings Driver
9	Value Engineering	Application of value engineering principles to optimize project outcomes across both design and construction phases. Activities include evaluating proposed project routes and project means and methods to proactively identify challenges and determine opportunities for improving constructability, reducing costs, and minimizing schedule impacts. Status: TRL 9	Drive standardization, efficiency, and overall project value, for optimal use of resources while maintaining safety and reliability standards.
10	Automated Utility Design Software	Automated Utility Design, also known as Graphic Work Design, involves software tools that incorporate greater automation and digitization in the design, redesign and quality verification of Undergrounding Projects. These tools leverage standardized design rules, templates, and system integrations to automate portions of the design process and result in standardized outputs that are typically easier to modify if redesign is needed. Status: TRL 8	The standardization and automation enabled by these software tools reduces the time needed for project design, redesign, and quality verification.
11	Field Design Change Software	The Field Design Change application would facilitate the distribution, tracking and recording of field design change requests, reviews, approvals, and denials from various lines of business. Status: TRL 5	By expediting reviews, validation and approvals, this software would enable quicker resolution when design changes are needed in the field.

d. Strategies for Achieving Sustainable Supply Chain and the Economies of Scale Necessary to Reduce Costs Over Time (EUP Guidelines Section 2.5.3(d))

Regulatory certainty associated with PG&E's EUP is critical to establishing and maintaining a sustainable supply chain and achieving the economies of scale necessary to reduce costs over time. PG&E has established a supply chain to deliver on our current pace of undergrounding which is adequate to support the program through at least 2029. However, a longer-term, clearly defined program would provide supply chain participants with the confidence needed to invest in capacity, workforce, and manufacturing capabilities aligned with growing program needs. Long-term regulatory approval would enable PG&E to transition from short-term procurement to more strategic, multi-year sourcing arrangements to further capture economies of scale.

With regulatory certainty around program scope and funding, PG&E will be able to pursue long-term agreements with key suppliers and manufacturers for materials such as cable, conduit, vaults, enclosures, and related equipment required for large-scale undergrounding. These longer-term agreements support unit cost reductions through volume commitments, reduced procurement volatility, and improved production planning. In several cases, suppliers have evaluated capital investments—including facility expansions—based on the trajectory of PG&E's growing Undergrounding Program. As undergrounding mileage scales over time, PG&E's purchasing power increases, creating meaningful economies of scale that are reflected in lower per-unit pricing and reduced transaction costs. Creating confidence around the 10-year outlook through an approved EUP will encourage suppliers to make those investments and reduce costs.

As the Undergrounding Program has expanded, PG&E has experienced material availability challenges, largely driven by broader upstream supply chain disruptions following the COVID-19 pandemic. These constraints have been addressed through a combination of production prioritization with incumbent suppliers, qualification and onboarding of additional vendors, and the use of approved alternate

materials where appropriate. Establishing a 10-year Undergrounding Plan will enable PG&E to more confidently forecast demand, coordinate with suppliers over a longer planning horizon, and reduce exposure to short-term market disruptions.

Long-term regulatory approval also supports continued refinement of PG&E's enterprise sourcing and delivery strategies, including standardization of new materials and technologies across programs, and integration of undergrounding material forecasts with other capital programs where appropriate. These approaches further enhance economies of scale, reduce variability, and support consistent execution as the program matures.

In parallel, PG&E remains committed to advancing supplier diversity as part of a sustainable and resilient undergrounding supply chain. Consistent with our Supplier Diversity Program, PG&E actively engages woman-owned (WBE), minority-owned (MBE), service-disabled veteran-owned (DVBE), and LGBT-owned (LGBTBE) business enterprises. Participation by diverse and small businesses supports local economic development, expands the qualified supplier base, and enhances overall program flexibility. PG&E will continue to identify opportunities for diverse suppliers to participate in the EUP.

Taken together, regulatory certainty, long-term planning, supplier diversification, and scale-driven sourcing strategies position PG&E to manage costs responsibly while delivering undergrounding in a manner that is sustainable and resilient.

D. Non-Ratepayer Funding Sources (EUP Guidelines Section 2.5.4)

Section 8388.5(j) requires the Large Electrical Corporation participating in the program to "apply for available federal, state, and other nonratepayer moneys throughout the duration of its approved undergrounding plan" and use acquired funds to reduce the program's costs to ratepayers. To fulfill this component, the EUP must contain:

a. List of existing nonratepayer funding opportunities;

b. A plan for identifying additional sources of nonratepayer funding and plans for tracking and applying for nonratepayer funding opportunities that may become available; and

c. A plan for tracking nonratepayer funds received to ensure the funds are used to reduce ratepayer costs.

PG&E is committed to maximizing opportunities that will reduce the costs of the EUP, including applying for external funding, such as federal and state funding, to offset program costs.

In this section we: (1) list the non-ratepayer funding opportunities PG&E has already pursued or is currently pursuing as of the date of the EUP submission; (2) describe our plan for identifying and tracking additional sources of non-ratepayer funding opportunities; and (3) describe our process for applying for those funds to PG&E's Undergrounding Program. PG&E anticipates updating this information in our Progress Reports to provide Energy Safety with information on relevant external funding opportunities applied for or received. This section also includes a brief discussion of PG&E's plan to comply with the SB 884 CPUC Guidelines adopted in Resolution (Res.) SPD-37 and the tracking requirements of CPUC Res. E-5254.

1. List of Non-Ratepayer Funding Opportunities (EUP Guidelines Section 2.5.4(a))

In compliance with Res.E-5254, PG&E submits a Tier 1 information-only advice letter quarterly to CPUC's Energy Division on the status of external

funding for which PG&E has applied.[150] Advice 5210-G/7903-E (April 30, 2026) includes information on the status of the 39 external funding opportunities to which PG&E has applied since PG&E's first Res.E-5254 report in Q3 2023.[151] As shown in Advice 5210-G/7903-E, PG&E's applications have been approved or conditionally approved for 26 of these 39 funding opportunities.

External funding sources have explicit criteria and conditions for how the funding may be used. Our undergrounding work may or may not meet those conditions. Of the three specific non-ratepayer funding opportunities PG&E has secured to-date that are relevant to PG&E's system hardening and wildfire mitigation activities, PG&E's undergrounding work may meet the conditions of one of them. The conditions of "Title 17 Clean Energy Financing - Energy Infrastructure Reinvestment Program" loan are still being finalized, and it has yet to be determined whether PG&E's EUP work will be eligible. If eligible, PG&E would apply available funding to offset the EUP costs. It is unclear at the time of this filing the degree to which EUP work will meet the conditions of any other future external funding grants and loans.

2. PG&E's Plan for Identifying Additional Sources of Non-Ratepayer Funding and Plans for Tracking and Applying for Non-Ratepayer Funding Opportunities (EUP Guidelines Section 2.5.4(b))

PG&E has a designated team (Strategic Financial Solutions) that manages the process to pursue non-ratepayer federal, state, or other third-party funding opportunities for PG&E programs and Projects. On a recurring basis, this team reviews federal, state and other investment

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[150] Quarterly Advice Letter Requirements include details of applications (such as status of application submitted to Department of Energy (DOE), assessment of future opportunities) and details of awards (such as total award, funds expended and remaining, project timeline and development status). For further details refer to Res.E-5254, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M506/K016/506016078.PDF (accessed May 11, 2026).

[151] Advice 5210-G/7903-E, available at: https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_5210-G.pdf accessed September 16, 2026).

programs for new funding opportunities including grants, loans, and other types of funding opportunities including potential funding from:

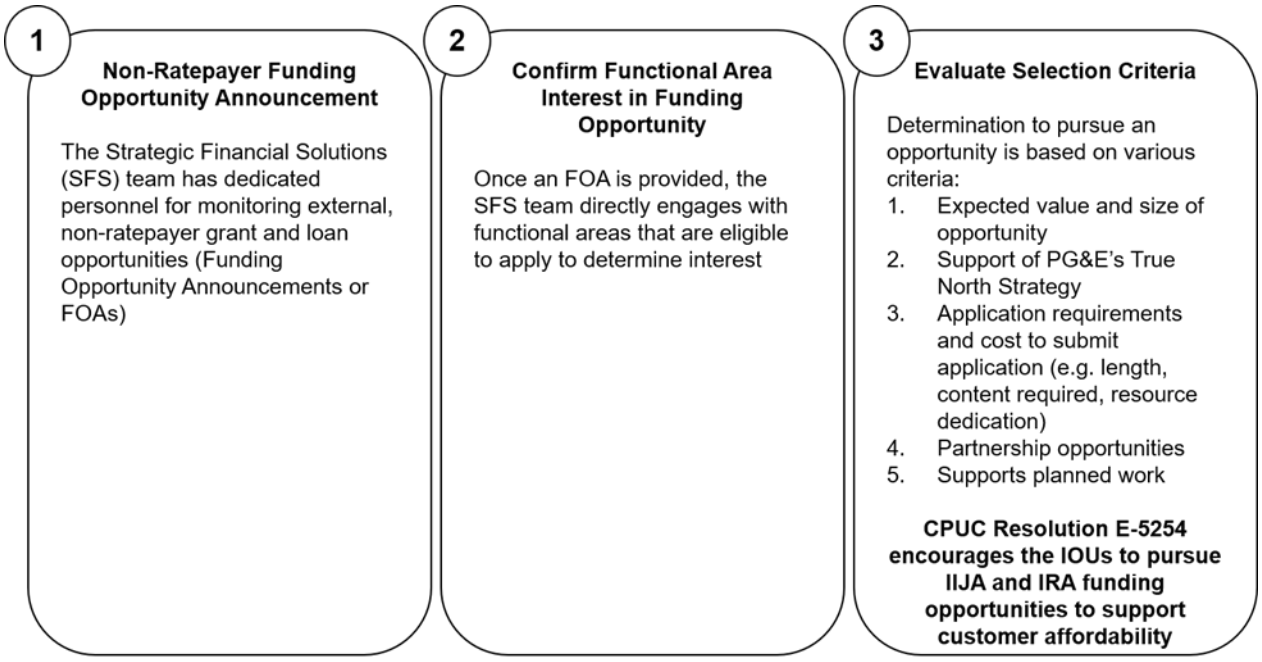
- DOE;
- California Energy Commission - administers state and federal funds, state bonds;
- CPUC proceedings that may enable other types of external financing;
- Department of Transportation;
- United States Department of Agriculture (USDA); and
- Tribal Rural Funding.

In addition, PG&E works with industry partners, such as the Edison Electric Institute, to leverage external processes that are tracking federal funding opportunities and will track state funding opportunities by monitoring on-going state legislation. Because these opportunities are dependent on external parties, the number of external funding opportunities and associated amounts will vary.

When PG&E identifies a potential funding opportunity, we evaluate its alignment with our business strategy, the benefits it would provide, the costs necessary to pursue the funding, and whether PG&E has the ability and resources available to prepare the application, and if awarded, to execute the Project and comply with funding requirements. In considering whether to pursue non-ratepayer funding opportunities for our Undergrounding Program, PG&E evaluates the following specific criteria:

- Strategic Alignment: Assess the alignment of the funding opportunity's goals with those of PG&E's Undergrounding Program. Goal alignment is imperative to delivering competitive Project proposals.
- Positive Impact on Benefits: Evaluate if the fund's desired outcomes deliver positive benefits to PG&E's Undergrounding Program and our customers. Apply for only those opportunities where this is true.
- Reduction in Costs: Determine if the net impact of the opportunity (discounting additional fund application and compliance costs) will reduce program costs.

FIGURE 5-1:
DECISION MAKING MATRIX FUNDING APPLICATION



When PG&E identifies an opportunity using these criteria, we develop and submit a funding application. If an application is successful and PG&E is awarded a grant or loan with financing terms that are more favorable to PG&E than our current loan Portfolio, we establish governance and accounting processes to comply with the grant or loan requirements, including oversight and monitoring of funding dispersal, compliance status, Project execution, benefits realization, and internal and external reporting.

3. PG&E's Plan for Tracking Non-Ratepayer Funds Received to Ensure the Funds are Used to Reduce Ratepayer Costs (EUP Guidelines Section 2.5.4(c))

PG&E cannot reliably forecast the type or scale of external funding opportunities that will be available during the EUP period, which of our third-party funding applications will be successful, how much external funding we may receive in any given year, or how much of that funding we would be able to use for EUP work. Thus, for ratemaking purposes, PG&E will need to evaluate the best method to reduce or refund customer costs received from third-party funding and will propose an efficient method to do this in our CPUC Phase 2 Cost Recovery Application. PG&E notes that

Generally Accepted Accounting Principles and the Federal Energy Regulatory Commission Uniform System of Accounts do not provide explicit rules or instructions for how companies should account for third-party funding such as government grants or loans. Like many other public companies, PG&E has referred to the International Financial Reporting Standards and their specific guidance under IAS 20, Accounting for Government Grants and Disclosure of Government Assistance for accounting guidance related to governmental assistance. PG&E also notes that different processes may be necessary to true-up – and thus reduce ratepayer costs – depending on any specific requirements of a particular loan or grant.

Process for Tracking Non-Ratepayer Funding Via the DOE Loan

PG&E has received approval from the CPUC to confirm the process of how savings will be returned to customers after we receive advances for eligible Projects costs under the DOE LGA. Within 60 days of a loan advance, PG&E will submit a Tier 2 Advice Letter calculating the resulting interest cost savings once draw down occurs. The savings will be returned to customers as a revenue credit though the Annual Electric True-Up and Annual Gas True-Up Advice Letters submitted each December for the following year.

E. Chapter Summary

Chapter 5 summarizes PG&E's approach to meeting four core topics: (1) Project timelines and annual targets for undergrounding work; (2) PG&E's workforce development plan to support delivery over the plan period; (3) evaluation of undergrounding costs and benefits (including benefit-cost analysis methods and cost containment strategies); and (4) identification and pursuit of non-ratepayer funding sources to reduce customer costs.

The chapter outlines how PG&E will present and manage schedules through a Target/Timeline table and a Project/Subproject management tracking template, along with controls to maintain schedule adherence. It also describes workforce planning assumptions, hiring and training approaches. Finally, it describes how PG&E evaluates costs and benefits using modeling (e.g., WBCA/BCR concepts) and sets out a process for finding, applying for, and

tracking external funding opportunities so that awarded funds can be used to offset ratepayer impacts.

F. Chapter 5 Supporting Attachments Index

The following workpapers/attachments outlined in Table 5-6 below support this chapter.

TABLE 5-6:
CHAPTER 5 SUPPORTING ATTACHMENTS/WORKPAPERS INDEX

Line No.	EUP Section	EUP Location	Workpaper / Table Name	File Name
1	5.C.1.a 5.C.3.c	Attachment B	WP002 (EUP Target / Timeline Table)	PGE_WP002_2026-~~09~~10-30_EUP Target Timeline Table_R0
2	5.C.3.a 5.C.3.b	Attachment B	WP006 (WBCA Whitepaper)	PGE_WP006_2026-~~09~~10-30_WBCA Whitepaper_R0
3	5.C.2.a	Attachment B	WP007 (Undergrounding Resource Model)	PGE_WP007_2026-09-30_Undergrounding Resource Model_R0
4	5.C.1.b	Attachment A-2	Progress Report 0 – Table C.14 Subproject Table	PGE_Initial_2026-~~09-30~~10-12_T14_R0
5	5.C.1.b	Attachment A-2	Progress Report 0 – Table C.23 Subproject Management Template	PGE_Initial_2026-~~09~~10-30_T23_R0
6	5.C.1.a 5.C.3.c	Attachment A	Progress Report 0 Narrative	PGE_AtchA_2026-~~09~~10-30_Progress Report 0 Narrative_R0

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 6

PROGRESS REPORT 0

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 6
PROGRESS REPORT 0

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) describes the content, structure, and rationale for Progress Report 0 to demonstrate how it satisfies the requirements of Senate Bill (SB) 884 and Electrical Undergrounding Plan (EUP) Guidelines Sections 2.6, 2.6.1, 2.6.2, and Appendix C. This chapter explains how Progress Report 0, included as Attach. A to the EUP, integrates narrative discussion, tabular data, JSON submissions,[152] and spatial datasets to provide a comprehensive and transparent snapshot of program status, risk modeling, project selection, and implementation planning at the time of EUP submission.

Section B lists the EUP Guidelines addressed in this chapter.

Section C discusses the data included in Progress Report 0. Progress Report 0 includes all data required by Sections 2.4.7.2, 2.8 and Appendix C of the EUP Guidelines. It also includes tables required by the California Public Utilities Commission (CPUC). This following information will be in Progress Report 0 and each subsequent Progress Report:

- 15 required tabular data submissions (EUP Attach. A-2 Tables C.1 through C.15) required by EUP Guidelines, Appendix C, Section C.1;
- A Non-EUP Project Table (EUP Attach. A-2 Table C.22) containing the Project Identification (ID), status, timeline, and risk reduction information for non-EUP system hardening projects as required by Section 2.4.7.2 of the EUP Guidelines;
- Two required JSON data submissions (Attachments A-3 and A-4) required in EUP Guidelines Appendix C, Section C.2;

[152] As defined in the EUP Guidelines, JSON or JavaScript Object Notation is a data file type designed to track unstructured data that would not be appropriate for a spreadsheet format.

- A geodatabase (EUP Attachment A-5) containing the six required spatial data schema listed in EUP Guidelines Appendix C, Section C.4;[153]
- Project List Data Requirement Tables (Tables SPD-1 to SPD-7) required by the CPUC Safety Policy Division[154] (EUP, Appendix D) and
- The Subproject Management Template (SPM Template) (EUP Attach A-2, Table C.23) which contains the schedule and milestones for each Confirmed Project and Subproject as required by Section 2.5.1.(b) of the EUP Guidelines.

Section D includes a chapter summary and Section E lists the attachments that support this chapter.

B. Undergrounding Plan Requirements

Tables 6-1 and 6-2 below identify the EUP Guidelines requirements that are addressed in this chapter. There are no statutory requirements addressed in this chapter.

TABLE 6-1:
SB 884 REQUIREMENTS ADDRESSED IN CHAPTER 6

Line No.	Public Utilities Code Section	Legislative Requirement	Where Requirement is Addressed
1		None	N/A

[153] Note, EUP Guidelines Appendix C, Section C.3 provides the technical requirements for the spatial data submissions listed in Section C.4.

[154] Safety Policy Division, SB 884 Project List Data Requirements Guidelines (May 11, 2026).

TABLE 6-2:
EUP GUIDELINES REQUIREMENTS ADDRESSED IN CHAPTER 6

Line No.	EUP Guidelines Section	EUP Guidelines Requirement	Requirement Reference in Chapter 6
1	2.6	Progress Report 0	Section C
2	2.6.1	Content of Progress Report 0	Section C.1
3	2.6.2	Relation of Progress Report 0 to Statutory Progress Report Requirement	Section C.2
4	2.8.1	Tabular Data Submissions	Section C.1.b
5	2.8.2	JSON Data Submission	Section C.1.c
6	2.8.3	Spatial Data Submissions	Section C.1.d
7	Appendix C	Content of Progress Report 0	Section C.1

C. Progress Report 0 (EUP Guidelines Section 2.6)[155]

The EUP must include a report called "Progress Report 0" as an attachment. Progress Report 0 must show the status of Circuit Segments and other matters related to wildfire mitigation at the time of EUP submission.

The Large Electrical Corporation must submit an updated Progress Report 0 every six months until the EUP start date including during the period the EUP is evaluated by Energy Safety and the CPUC. During this time period, Energy Safety may direct the Large Electrical Corporation to make changes to the format and content of Progress Report 0.

The EUP must contain a narrative explaining the Large Electrical Corporation's choice of content and structure for Progress Report 0. The narrative must explain and confirm how Progress Report 0 meets the requirements in Sections 2.6.1 and 2.6.2 below.

We are providing Progress Report 0 as Attach. A to this EUP. PG&E will submit an updated Progress Report (labeled Progress Report 1, 2, etc.) semiannually following Energy Safety's decision on PG&E's EUP and the CPUC's decision on our Phase 2 Application consistent with the requirements of Public Utilities Code Section 8388.5(f)(1). Progress Reports will be posted on PG&E's external website at the following site: www.pge.com/eup.

155 Energy Safety modified its guidance about when a utility should submit a Progress Report in its Frequently Asked Questions, dated July 8, 2026. Question 13 states: "Section 2.6 of the EUP Guidelines states that the Large Electrical Corporation is required to submit an updated Progress Report 0 every six months until the EUP start date. However, Energy Safety will not require the Large Electrical Corporation to submit an update to Progress Report 0 during Energy Safety's evaluation of the EUP. Progress Reports are due every six months after the start date of the EUP."

1. Content and Structure of Progress Report 0 (EUP Guidelines Section 2.6.1)

Progress Report 0 must be based on information and data available at the time of submission. The Circuit Segment Information Lists, including the Confirmed Projects List and the Prioritized Project List, submitted in Progress Report 0 must meet the minimum requirements described in Section 2.4.1 for Screen 3.

Progress Report 0 must, at a minimum, include the following sections:

a. Portfolio Coversheet (narrative);

b. Example Rejected Project(s) (see Section 2.4.5.2, Twenty Five Undergrounding Project Requirement);

c. Plan Mitigation Objective (narrative);

d. Plan Tracking Objectives (narrative);

e. Target/Timeline Table (narrative);

f. Identified Wildfire Rebuild Areas (narrative);

g. Model Report (see Section 2.7.2);

h. Alternative Mitigation Selection Process (narrative);

i. All data required pursuant to Section 2.8 and Appendix C of these Guidelines; and

j. Any additional System Level, Portfolio Level and Project Level information the Large Electrical Corporation would like to be included in Progress Reports.

Below PG&E explains how Progress Report 0 is organized to meet the structure and content requirements of EUP Guidelines Sections 2.6.1, 2.8.1, 2.8.2, 2.8.3, and Appendix C.

In addition to the tabular data required by Energy Safety, PG&E is including seven data tables required by the CPUC in Resolution SPD-37, Appendix 1 as required by SPD in the *SB 884 Project List Data Requirements Guidelines* issued May 11, 2026. These tables are included in the EUP as Attach. D. The tables will be updated in each Progress Report. See Chapter 3, Table 3-9 for a description of the comparison types described below.

a. Narrative Sections of Progress Report 0

Progress Report 0 includes sections for the narratives required in Section 2.6.1 of the EUP Guidelines to be included both in the EUP and the Progress Report.

Accordingly, our Progress Report 0 narrative relies on references to the applicable chapters and sections of the EUP. PG&E's Progress Report 0 identifies the location of the narrative in the EUP instead of providing a duplicative narrative. References have been added to clearly direct the reader to the relevant sections of the EUP where the required Progress Report 0 narrative content is addressed. This approach reflects that Progress Report 0 is based on information available at the time of submission of the EUP.

In future Progress Reports, PG&E will update the narrative for any sections that have changed since the prior report, including updates to assumptions, methodologies, data inputs, or implementation status, consistent with the reporting requirements of the EUP.

Each of the required narratives, the location of the narrative in the EUP, and their location in the Progress Report, is set forth in Table 6-3 below.

TABLE 6-3:
REQUIRED NARRATIVES IN PROGRESS REPORT 0
(EUP GUIDELINES SECTION 2.6.1)

Section 2.6.1 Subsection	Requirement	EUP Location	Progress Report Section
a	Portfolio Coversheet	Chapter 9	PR 0 Section A
b	Example Rejected Project	Chapter 3, Section D.3.b	PR 0 Section B
c	Plan Mitigation Objective	Chapter 2, Section D	PR 0 Section C
d	Plan Tracking Objectives	Chapter 2, Section E	PR 0 Section D
e	Target/Timeline Table	Chapter 2, Section D.1.j	PR 0 Section E
f	Identified Wildfire Rebuild Areas	Chapter 3, Section D.1.a	PR 0 Section F
g	Model Report	Chapter 7, Section D	PR 0 Section G
h	Alternative Mitigation Selection Process	Chapter 3, Section D.2	PR 0 Section H
i	All Data required by Section 2.8 and Appendix C	Chapter 6, Section C.1, Chapter 9 Sections D-G	PR 0 Section I and Portfolio Coversheet
j	SPD-37 Appendix 1 Data Submission	Attach. D	PR 0 Section J

b. Tabular Data Submissions in Progress Report 0 (EUP Guidelines Section 2.6.1(i) and Section 2.8.1)

Progress Report 0 includes the tabular data that is required in EUP Guidelines Appendix C, Section C.1 using the table numbers in Appendix C and data from our risk and operational models. Progress Report 0 was prepared with the data templates available on Energy Safety's website.[156] PG&E's tabular data including Tables C.1 – C.15, C.22, and C.23, can be found in Attach. A-2 Progress Report 0 Tabular Data Submission.

Below, PG&E provides a description of the data and key assumptions and limitations to the data, which may be adjusted in future Progress Reports.

1) Plan Table (Table C.1)

a) Table Description

Plan Table C.1 provides summary information about the EUP, including the start and end dates of the EUP, the date we submitted the plan to Energy Safety, and a unique plan identification number. We also provide our High-Risk Threshold, Ignition Tail Risk Threshold, and High Frequency Outage Program Threshold in EUP Chapter 3, Section D.1.

Table C.1, which contains a single row of data, will only be submitted with Progress Report 0 and will not be updated.

b) Assumptions and Limitations

PG&E's Project-Level Thresholds are discussed in Chapter 7, Section M.1.

2) Key Decision-Making Metric Table (Table C.2)

a) Table Description

In Key Decision-Making Metric (KDMM) Table C.2, we provide the values for each KDMM, an indication of whether the

[156] The data templates are available at: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/https-energysafety-ca-gov-what-we-do-electrical-infrastructure-safety-undergrounding-and-culture-division-sb-884/ (accessed May 11, 2026).

KDMM is cumulative or non-cumulative, and an explanation of each KDMM. This table will be used as the official reference for KDMM_number and KDMM_name. The project_variable_modifiers and risk_landscape JSON files will use the KDMM_number and KDMM_name values in Table C.2.

Table C.2 will only be submitted with Progress Report 0 and will not be updated.

b) Assumptions and Limitations

We assume that "cumulative" as used in the instructions for Table C.2 indicates that the KDMM can be instantaneous or cumulative. Conversely, "not cumulative" indicates that the KDMM can only be instantaneous.

3) Risk Model Version History Table (Table C.3)

a) Table Description

Table C.3 lists each of our risk model versions, provides a value identifying the version or calibration number for this risk model version, the date the version or calibration was established, and a description of the changes and updates when new versions or calibrations are established. PG&E expects to consolidate risk model calibrations into risk model version updates (see EUP Chapter 8 for a description of risk model and calibration details and nomenclature). The risk model information in Table C.3 will match the information in the accompanying JSON Data Submission.[157]

Table C.3 will be resubmitted with all future Progress Reports and will be updated if new risk model versions or calibrations are introduced.

b) Assumptions and Limitations

The risk model referenced in the instructions for Table C.3 is understood to refer to the Wildfire Benefit Cost Analysis

[157] See Appendix C, Section C.2 of the EUP Guidelines for description of JSON Data Submissions.

(WBCA). PG&E's Outage Program Risk Model (OPRM) and Wildfire Distribution Risk Model (WDRM v4) are incorporated into the WBCA.[158]

4) Portfolio Table (Table C.4)

a) Table Description

Portfolio Table C.4 lists all Confirmed Projects and the total number of Circuit Segments in the Portfolio. It also includes a narrative overview. This table provides the source of portfolio_ID, which will be a unique identifier that identifies a comprehensive list of all Confirmed Projects.

In subsequent Progress Reports, PG&E will describe changes to the EUP since the previous Progress Report, including the creation of new Portfolio IDs representing the addition and/or removal of projects to the EUP. PG&E will also chart the development of the number of Projects contributing to the EUP Portfolio in the Portfolio Coversheet, as required in Section 2.8.6.3 of the EUP Guidelines.

Additionally, we will provide the start date of the EUP, the estimated completion date of the final project in the Portfolio, the current risk model version and calibration IDs for the risk model.

Table C.4 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

The Portfolio ID is a unique value that represents the comprehensive and cumulative list of Projects that have been confirmed to date. For example, in Progress Report 0, there will be a single Portfolio ID (e.g., "P01") assigned to the projects included in the first Progress Report. Only Confirmed Projects that have passed Screen 3 will be included in the Portfolio. Projects which do not pass Screen 3 and which proceed with no undergrounding will be included in the Non-EUP Project Table,

[158] Risk Model Version ID and Risk Model Calibration ID are also in Tables C.4, C.5, C.8, and C.10. Calibration Date is also in Table C.5.

but will not be attributed with the Portfolio_ID or a Project_ID. In future Progress Reports, any Confirmed Projects that are added will be combined with the list of Projects from the previous Progress Report, and all will be assigned the Portfolio ID P0x+1. Numbering will continue sequentially in future Progress Reports as new projects are added or removed.[159] In this context, "x" is an integer starting at 0, to align with the Progress Report number, e.g., P00, P01, P02, etc.

5) Risk Model Backtesting Table (Table C.5)

a) Table Description

Table C.5 identifies the current risk model versions and calibration number for the risk models, the date the calibration was established, and the date of the Baseline used for the modeling. Each row of this table will be the application of the current risk model version and/or calibration to a Baseline and Portfolio. In Progress Report 0, PG&E will submit a single row applying the current risk model to the initial system Baseline and to the first Portfolio. In future Progress Reports, PG&E will apply the current risk model to both the existing Baseline and to a new Baseline if established prior to that future Progress Report.

PG&E will also apply the current risk model to the new Portfolio submitted with future Progress Reports, resulting in two rows of data for the current risk model version and calibration. Any new risk model or calibration will be applied to prior Baselines and Portfolios. Following the release of a new risk model or calibration, the previous risk models and calibrations will be applied to future Baselines and Portfolios.

Additionally, for each KDMM we provide: the KDMM Baseline value; the KDMM uncertainty under the current modeling conditions; the KDMM value by applying the specified

[159] This field also appears in Tables C.5, C.9, C.10, C.11, C.12, C.13, C.15, C.17, C.18, C.19, C.20, and C.21.

risk model to the specified Portfolio; and the KDMM uncertainty under these modeling conditions for that specific Portfolio. Baselines will be updated annually,[160] and updated Baseline values will be shown in the first Progress Report of every calendar year. Baseline values will reflect the sum of all Circuit Segment values for each KDMM for the entire distribution system at the time of the Baseline date. Portfolio values will reflect the sum of all Circuit Segment values for each KDMM within each specific portfolio version. Uncertainties will be provided at the same levels of aggregation: system-wide for Baseline uncertainty, and Portfolio-specific for Portfolio uncertainty. The methodologies used to derive uncertainties for each of the seven KDMMs are described in Chapter 7, Section E.

Table C.5 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

There are currently limitations on PG&E's ability to backtest new risk model versions and/or calibrations against old risk model versions that would yield accurate risk outputs. Circuit Segment geometry and Circuit Segment names are generated from the risk model using a snapshot of the distribution grid at a specific point in time. The snapshot of the Circuit Segment is a critical component in how risk is modeled from attribute data that is aligned in time with the grid configuration. Each new risk model version is developed using the latest and most useful attribute information available and the specific attributes used to produce the best risk estimations will not necessarily have equivalents when the prior risk model version was developed.

Due to the limitations in our ability to use new model versions to make predictions on historic asset and

[160] See Energy Safety EUP Frequently Asked Questions (July 8, 2026), Question 12 confirming Baselines must be updated once per calendar year.

environmental data, PG&E will rely on the Circuit Segment changelog table (Table C.7) to make assumptions about how risk values produced from previous model versions have been redistributed to different Circuit Segments due to changes in Circuit Segment geometry. PG&E notes that changes in the data cannot be attributed specifically to changes in model architecture nor to changes in underlying data.

6) Circuit Segment Identification Table (Table C.6)

a) Table Description

For each Circuit Segment in our service territory, PG&E will indicate in Table C.6 if the Circuit Segment has passed Screen 1, provide information about the Circuit Segment location (e.g., HFTD tier, Fire Rebuild Area, county), and identify Circuit Segments which include Non-EUP Projects. PG&E has appended two additional columns for transparency to identify the length of the HFTD and HFRA miles on a Circuit Segment. These columns are named hftd_only_circuit_segment_length and hfra_only_circuit_segment_length, respectively.

We also indicate whether the Circuit Segment is planned for system hardening as a Non-EUP Project and identify the applicable system hardening mitigation(s) and corresponding program. Every Circuit Segment in Table C.6 will have a matching Circuit Segment in the Circuit Segment geospatial feature provided in the accompanying Geodatabase (GDB) (C.4.1 Circuit Segment (Line Feature Class)) and its attribute table, C.16). Table C.6 will be updated with a new list of Circuit Segments if the risk model changes.

Table C.6 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

The Circuit Segment ID field is dependent on the risk model version used, where a synchronized set of all equipment asset configuration data, commonly referred to as a “snapshot,” is

collected for a specific point in time for WDRM development consistency. Only Circuit Segments that are identified in the WDRM and are used in WDRM risk calculations will be listed in this table. To avoid reusing old Circuit Segment IDs in subsequent versions of the risk model, we rename all Circuit Segment IDs in every risk model version.[161]

The template provided for this table for data field qdr_circuit_segment_id specifically requests that the Circuit Segment reported in the most recent WMP be included. This value will be 'NULL' because PG&E does not currently provide a full list of Circuit Segments with corresponding planned mitigations in our WMP or Wildfire Mitigation Data Report (WMDR).

The circuit_segment_length field will provide primary overhead miles on an entire Circuit Segment.

We are counting a Circuit Segment as a Confirmed Project if the Project is 100 percent Underground, or an Additional Comparison project that includes undergrounding and has passed Screen 3. Conversely, we define a Non-EUP Project as a Circuit Segment with non-undergrounding system hardening work planned or in construction that is not a Fire Rebuild Area, HFTD Tier 2, or HFTD Tier 3 Circuit Segment, and that has not passed Screen 3. If a Circuit Segment has been scoped and there is no undergrounding, we note it as "False." If a Circuit Segment has not been scoped at the time of the Progress Report submission, this value is reported as 'NULL.' It is possible that a Circuit Segment may be a Non-EUP Project at one time and then be scoped for undergrounding in a future Progress Report. For example, a project may originally be selected as a Remote Grid, and the Remote Grid is not possible for any reason, such as customer consent not being provided,

[161] This field also appears in Tables C.7, C.8, C.9, C.10, C.11, C.12, C.13, C.14, C.15, C.16, C.17, C.18, C.19, C.20, and C.21.

we would need to revert to the next available mitigation, which could include undergrounding.

In Table C.6, only one county value will be reported, and will be determined by analyzing which county most of the Circuit Segment's geometry falls within.

We assume that a Circuit Segment's identification as a Fire Rebuild Area is based on one of two sources: (1) the existence of a Fire Rebuild order on the Circuit Segment, or (2) the existence of any previous recorded 'fire' tag within 5 meters of Circuit Segment geometry. The Circuit Segment length represents the total pre-mitigation primary overhead length of a Circuit Segment.[162]

The Project ID will be 'NULL' until the Project ID is created after the project passes Screen 3.[163] PG&E's screen process assigns a Project ID in Screen 3 to scoped projects. The project ID will be retroactively assigned to Circuit Segments in the Screen 2 Table.

The HFTD Tier reported for each Circuit Segment represents the highest HFTD designation encountered along the segment. Accordingly, segments that traverse both Tier 2 and Tier 3 HFTD areas are designated as Tier 3. The county reported is the county containing the highest percentage of conductor footage within the Circuit Segment. For example, if a segment spans multiple counties, the county with the greatest share of conductor is reported.

7) Circuit Segment Changelog Table (Table C.7)

a) Table Description

In Table C.7, we will report changes to each Circuit Segment in our service territory including the type of change, change date, and the Circuit Segments that contributed to the

[162] This field also appears in Table C.15.

[163] This field also appears in Tables C.8, C.9, C.10, C.11, C.12, C.13, C.14, C.15, C.17, C.18, C.19, C.20, and C.21.

new segment. PG&E will only update the changelog if required by the risk model update and calibration process as discussed in Chapter 8.

Table C.7 is not submitted with Progress Report 0 but will be submitted with subsequent Progress Reports.

b) Assumptions and Limitations

Not applicable as all relevant assumptions and limitations are already captured in the above tables.

8) Circuit Segment Risk Score Table (Table C.8)

a) Table Description

In Table C.8 we will identify, for each Circuit Segment in our service territory, the current risk model version and calibration, risk category eligibility (High-Risk, Ignition Tail Risk, High Frequency Outage Program Risk, none), and the risk score and risk rank for each KDMM at the system and Portfolio levels. Each row will be a unique Circuit Segment and will match a unique Circuit Segment value in the Circuit Segment Identification Table (C.6). The list of Circuit Segments in this table will change if the risk model changes and updated risk model data will be shown accordingly. Risk model changes to the list of Circuit Segments will also be reflected in the Circuit Segment Identification Table (C.6) and in the Circuit Segment Changelog Table (C.7).

Table C.8 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

The Project ID will be 'NULL' until the Project ID is created after the project passes Screen 3. PG&E's screen process assigns a Project ID in Screen 3 to scoped Projects. Once assigned in Screen 3, the Project ID will be retroactively assigned to Circuit Segments in the Screen 2 Table.

Only Circuit Segments that are identified in the WDRM and are used in WDRM risk calculations will be listed in this table.

Per Energy Safety feedback during the pre-submission process, the various rank fields (i.e., overall_utility_risk_rank_system[164], overall_utility_risk_rank_portfolio, ignition_consequence_rank_system, ignition_consequence_rank_portfolio, outage_program_likelihood_rank_system, outage_program_likelihood_rank_portfolio) are not normalized by Circuit Segment mileage.

9) Screen History Table (Table C.9)

a) Table Description

Table C.9 provides a screen history for each Circuit Segment and indicates if an Undergrounding Project is being considered for the next screen, confirmed, prioritized, or preparing for construction.

In this table, PG&E will provide a row for each screen applied to each Circuit Segment. Circuit Segments which have not passed Screen 1 will not be included in Table C.9. In each subsequent Progress Report, additional rows will be added to the table to reflect additional screens that individual Circuit Segments have passed through. The data associated with prior rows will not be modified.

Table C.9 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

All requirements for the Screen History Table are based on the Circuit Segment ID for any Projects that have not passed Screen 3, since Project ID is only available after a Circuit Segment passes Screen 3.

We define a Project as “active” unless it is either defunct or complete, as identified in Table C.10: Project Table.

[164] Please note this field is not the same data point (i.e., used in the Screen 4).

Since both Screen 1 and Screen 2 are passed simultaneously in our process, the Screen 1 passed date and Screen 2 passed date will always be the same.

10) Project Table (Table C.10)

a) Table Description

For each Undergrounding Project, we will provide the following data: the CPUC project code(s) (PG&E's Maintenance Activity Type (MAT)); the risk category eligibility; PG&E's service territory division(s) and county(s) where the project is located; HFTD tier or Fire Rebuild Area; customer count; feasibility score; risk model version and calibration; selection justification; project priority; overlap with the WMP; risk tranche; associated Subprojects; whether a project is confirmed, and if the project is complete or defunct (no longer intended for construction.) Table C.10 will be based on a list of Circuit Segments which have passed Screen 2 and will identify which projects have not been confirmed for undergrounding in Screen 3.

Table C.10 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

We assume that Circuit Segment vintage only applies to Undergrounding Projects that have passed Screen 2 and have a Project ID assigned.[165]

The County and Division location data for a project will be based on the overlap with that project's Circuit Segment geometry in any County or Division; therefore, multiple County values may be reported within the Planning Order (PO) number.[166] Multiple POs may be required to invoice the respective county.

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[165] This field also appears in Table C.17.

[166] The County field also appears in Table C.15.

To count the number of customers served by a Circuit Segment, we assume that a 'customer' represents a unique Service Point ID (SPID). We assume that if a SPID is downstream of (i.e., connected to) a transformer that is within a planned or completed system hardening mitigation, then that customer is being served by the Circuit Segment where work is taking place.

Consistent with the Guidelines, PG&E provides the Feasibility Score as an integer; however, for purposes of estimating unit costs and calculating the associated BCRs for mitigation alternatives, PG&E applies a more granular feasibility assessment that underlies the reported integer score.

For Project Priority, until a sufficient volume of Projects has been planned, it is not possible for us to prioritize Projects beyond their EUP rank (i.e., monetized Overall Utility Risk reduced per primary overhead mile removed of the Project) except by prioritizing Wildfire Rebuild Projects. PG&E treats Screen 4 prioritization as a single occurrence applied to each Project upon completion of Screen 3 but may revise initial Project priority designations under specific conditions. (See Chapter 3, Section D.4 for further details on PG&E's prioritization approach.)

PG&E will only report the WMP Utility Initiative Tracking ID, and whether the project overlaps with a current or historical WMP periods for Confirmed Projects and Non-EUP Projects. We assume that WMP Utility Initiative Tracking ID is based on mileage by mitigation type and can be derived at the scoping phase, meaning it will not need to be updated later in the Project life cycle.[167]

In the list of Subprojects associated with each Project, we assume that a Subproject is located on a single Circuit Segment and is associated with a single Project_ID.

[167] This field also appears in Tables C.6 and C.14.

We consider a Project to be complete once all spans on all Subprojects are checked for quality assurance. Conversely, we consider a Project to be defunct if all Subprojects are cancelled or removed from a workplan at a given time.

11) Screen 2 Table (Table C.11)

a) Table Description

In Table C.11, for each Undergrounding Project that has passed Screen 2, PG&E will list the information required in Appendix C, Section C.1.11 (Screen 2 Table), including: the Plan ID, Project ID, comparison name (which may include 100 percent Underground, Alternative Mitigation 1, Alternate Mitigation 2, or Additional Comparison 1, the Portfolio ID, the Circuit and Circuit Segment IDs, a description of the mitigation work that will be performed, the safety, reliability, and financial benefits, the total risk reduction, unit cost per overhead mile deenergized, unit cost per mile of undergrounding, total mitigation cost, and BCR for each comparison (see Chapters 5 Section C.3.a and Chapter 7 for further details on the BCR methodology). Table C.11 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

Unit Cost Per Overhead Mile De-Energized represents the initial capital installation cost divided by the primary overhead HFTD miles removed or replaced by the mitigation. Note, PG&E is populating cells for Additional Comparison 1, in addition to 100 percent Undergrounding.

Unit Cost Per Circuit Mile Energized represents the initial capital installation cost divided by the energized primary overhead miles installed as part of the mitigation. For undergrounding, a conversion factor is applied, reflecting the assumption that each mile of overhead line replaced requires approximately 1.25 miles of underground installation. No conversion factor is applied to non-undergrounding mitigations.

PG&E presents Total Costs as the capital costs to install the mitigation measure and the associated operations and maintenance (O&M) costs over the life of the asset. These values do not include baseline costs (e.g., O&M expenditures for existing infrastructure). Accordingly, they differ from the costs used in the Benefit-Cost Ratio (BCR) calculation, which are calculated as lifetime costs net of the baseline.

12) Screen 3 Table (Table C.12)

a) Table Description

In Table C.12 we will list the Undergrounding Projects that have passed Screen 3. For each project, PG&E will provide the information required in Appendix C, Section C.1.12 (Screen 3 Table), including: the Plan ID, Project ID, comparison name which may include 100 percent Underground, Screen 3 Alternative Mitigation, Additional Comparison 2 or Additional Comparison 3, a narrative detailing how the mitigation was selected; the work type; the fraction of the Circuit Segment that will be undergrounded; whether the Project fulfills the Project-Level Standard; additional justification for applicable Projects; the Overall Utility Risk, Wildfire and Outage Program Risk reduction at Year 55; and the mean ignition consequence and mean outage program likelihood in the first 10 years of the EUP, for each comparison.

PG&E will recalculate and update the values in Table C.12, if updates to the Risk Model Version change their values. PG&E will update data in this table attributed to the 'Project as Scoped' comparison of a given project, if the Subprojects on that Project change in a way that alters Screen 3 data after the Project has passed Screen 3. Each row in Table C.12 (Attachment A-3) will be accompanied by an entry in the JSON file as required by EUP Guidelines C.1.13.

EUP Guidelines Section 2.4.1, Screen 3 procedure requires us to apply Screen 3 (Project Risk Analysis) to all

Undergrounding Projects which have passed Screen 2 and for which we have sufficient information to fulfill modeling requirements per EUP Guidelines Section 2.7. Screen 3 must be applied to a Portfolio of at least 25 individual Undergrounding Projects at the time of EUP filing.

Table C.12 includes all the analytical data and other information obtained through the Project development process for the individual Undergrounding Projects included in PG&E's EUP, including the expected wildfire risk reduction and reliability increases for each Undergrounding Projects and the comparative risk metrics for undergrounding and Alternative Mitigations.

Table C.12 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

With respect to the options listed in the EUP Guidelines for the Comparison Name field, we assume: (1) Project as Scoped will always reflect undergrounding or hybrid mitigations that include undergrounding; (2) Undergrounding as Scoped will always be the portion of the Project that will be underground[168]; and (3) Project Baseline assumes no build.

In addition to these three alternatives, PG&E will include (4) Screen 3 Alternative Mitigation, which will always reflect a 100 percent overhead hardening mitigation; and (5) up to two Additional Comparison values as follows: Additional Comparison 2, a hybrid option that includes undergrounding, overhead hardening line removal or remote grid mitigations, and Additional Comparison 3, and which will be described in the Work Type Description field. Finally, in the event the 'Project as Scoped' is not selected as the '100 percent Underground' option, PG&E will include a '100 percent Underground' option

[168] Note, the 10 year and 55 year cumulative risk for Undergrounding as Scoped includes all unmitigated, residual risk on the circuit segment, as required.

for comparison. Each of these alternatives and additional comparisons will be presented for every Undergrounding Project.

The '100 percent Undergrounding' comparison represents the maximum feasible level of undergrounding within the constraints of the Project and should not be interpreted as indicating that all work is undergrounding or that the entire Circuit Segment is undergrounded. Accordingly, the comparison may include associated overhead work, which may be reflected in this table.

13) Screen 4 Table (Table C.13)

a) Table Description

In Table C.13, for each Confirmed Project that has passed Screen 4, PG&E will list the information required in Appendix C, Section C.1.13 (Screen 4 Table), including: the Plan ID, Project ID, Circuit ID, Circuit Segment ID, Portfolio ID, Project Priority, the name of the comparison considered (which may include Project as Scoped, Undergrounding as Scoped or 100 percent Undergrounding, Screen 3 Alternative Mitigation or Additional Comparison 2 or 3), the work type, a description of the type of mitigation (including all types of system hardening mitigations that will be applied on a single Circuit Segment); the portion (fraction) of the Circuit Segment that will be undergrounded, safety, reliability and financial benefits, total risk reduction, unit cost per overhead mile deenergized, unit cost per mile of undergrounding, total mitigation cost, and the BCR.

If the CPUC changes any of the definitions used for this table (i.e., BCR), PG&E will recalculate and update the affected data. If a Risk Model Version update changes the values of any of the data in this table, PG&E will recalculate and update the data. If the 'Project as Scoped' changes in such a way that it receives new alignment IDs, PG&E will update the data in this

table that is impacted by alignment changes. Any required changes will be made in the Progress Reports.

Table C.13 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

Details regarding PG&E's prioritization of each Confirmed Project in Screen 4 are in Chapter 3, Section D.4, Screen 4: Project Prioritization and Finalization (EUP Guidelines Section 2.4.6).

PG&E assumes that an update to the pre_mitigation_alignment_ID field from Table C.18 for any Subproject on a given scoped Project will require an update to affected data in Table C.13 for that Subproject.

14) Subproject Table (Table C.14)

a) Table Description

In Table C.14, PG&E will list for each Confirmed Project: all Subprojects included in the Confirmed Project (each row will be a single Subproject); the Subproject mitigation type(s); the reason the Subproject was selected; whether the Subproject is in the WMP and, if so, the WMP ID and WMP cycle; the risk reduction due to undergrounding, and expected completion date; whether the Subproject is active or abandoned; pre and post-mitigation alignment ID mapped to a geospatial submission; the length of pre-mitigation overhead miles and post-mitigation overhead hardened or underground miles; whether we need a new right-of-way or easement to perform the work; and the current Project status and the date the Subproject was moved to its current status. Subprojects are not decision-making units, and Subproject level risk data is for reporting and tracking of discrete work units only.

PG&E's 'Subproject_ID' will be a string representing the Project ID, MAT code(s) included in the scope of the Subproject, and the mitigation represented by the Subproject.

The Subproject Table contains a field 'subproject_justification' which will include any justification for cases where pre-mitigation conductor geometry in GIS Feature C.4.3 falls outside the boundaries of the Project Polygon for the Project in GIS Feature C.4.2.

We will also provide the 'order_number' associated with the Subproject. This 'order_number' will be one or more PG&E planning orders and cover multiple individual Plant Maintenance Orders (PM Orders). There will be multiple PM Orders per planning order, and one or more planning orders per Subproject. Figure 6-1 below illustrates the relationship between Projects, Subproject and PM Orders.

FIGURE 6-1:
PROJECT, SUBPROJECT AND PM ORDER HIERARCHY

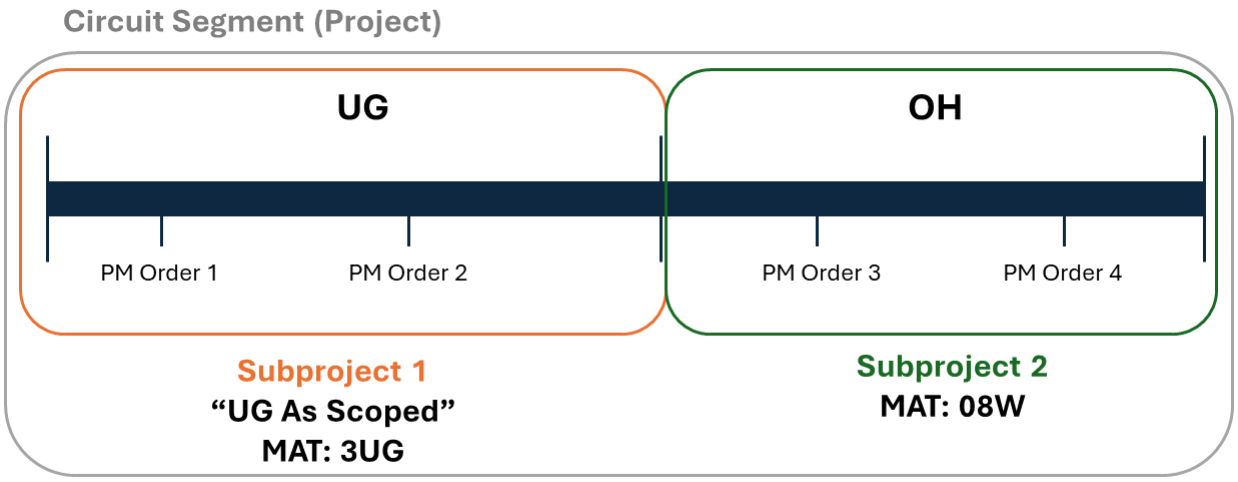


Table C.14 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

We are making the following assumptions for Table C.14: (1) the year a Subproject is completed is the applicable year for determining the applicable WMP cycle for that Subproject; (2) Subprojects may be completed in stages and reported in

multiple WMP cycles, meaning that multiple WMP cycle values may be reported for a single Subproject; (3) the Project and Circuit Risk Reduction Fraction is a function of mileage, calculated on a pro-rata basis; and (4) Pre-Mitigation Length is based on primary overhead footage only.

15) Project Index Table (Table C.15)

a) Table Description

For each Undergrounding Project which has passed Screen 2, PG&E will provide updated Project information as the Undergrounding Project passes through Screen 3 and Screen 4 as required in EUP Guidelines Appendix C, Section C.1.15 (Project Index Table).

Table C.15 contains the following data points for each Confirmed Project: Plan ID, Portfolio ID, Project ID, Circuit Segment ID, Circuit ID, Circuit Segment Length, County, Project Category ("Risk Category" from Table C.10), Project Priority (if the Project has passed Screen 4), and HFTD Tier. Table C.15 also contains Boolean fields flagging whether a Project is confirmed and/or prioritized.

Table C.15 also contains the following compiled metrics from the Tables C.11-C.13 (Screen 2, 3 and 4 Tables) for specific alternatives considered for each Undergrounding Project that has passed Screen 2:

For the "100 percent Underground" Alternative from Table C.11 (Screen 2 Table): the Total Costs, Total Risk Reduction, and BCR.

For the "Project as Scoped" Alternative from Table C.13 (Screen 4 Table): the Percent Undergrounded, the Total Costs, Total Risk Reduction, and BCR.

For the Screen 2 "Alternative Mitigation 1" from Table C.11 (Screen 2 Table): the Work Type Description, the Total Costs, Total Risk Reduction, and BCR.

For the Screen 2 “Alternative Mitigation 2” from Table C.11 (Screen 2 Table): the Work Type Description, the Total Costs, Total Risk Reduction, and BCR.

For the “Screen 3 Alternative Mitigation” from Table C.12 (Screen 4 Table): the Work Type Description, the Total Costs, Total Risk Reduction, and BCR, if the Project has passed Screen 4.

For the “Project Baseline,” “Project as Scoped,” and “Screen 3 Alternative Mitigation” from Table C.12 (Screen 3 Table): the Cumulative Risk which would accumulate over 55 years under each project type.

The information in this table will be compatible with the information submitted elsewhere in the data submission and will reflect the most current information as of each Progress Report.

b) Assumptions and Limitations

All assumptions and limitations that apply to Tables C.10-C.13 apply to Table C.15, as those tables constitute the data sources for Table C.15.

16) Non-EUP Project Table (Table C.22)[169]

a) Table Description

PG&E will provide a supplementary table (Table C.22) to the Progress Report containing a list of Non-EUP Projects that are conducted to reduce Wildfire Risk and Outage Program Risk, Circuits, Circuit Segments, Project Status, Project Timeline, and Project Risk Reduction, in accordance with Section 2.4.7.2 of the EUP Guidelines.

b) Assumptions and Limitations

Targeted System Hardening Non-EUP Projects will be defined during Screen 3 and understood to identify Circuit Segments on which no EUP undergrounding will take place. Circuit Segments with other non-EUP work will be identified and

169 Tables C.16 to C.21 are discussed below in Section C.1.d.

added to the Non-EUP Project Table when work is scoped. These Non-EUP Projects will not be assigned Project IDs. Project Timeline is defined by the range of years in which work will be done on a Project, from scoping to de-energization.

17) Subproject Management Template Table (Table C.23)

a) Table Description

For each Confirmed Project, the Subproject Management Template[170] (SPM Template) tracks the forecasted completion dates of key milestones for all Subprojects (including Undergrounding Subprojects and non-undergrounding Subprojects). The SPM Template addresses the milestones required in EUP Guidelines Section 2.5.1 (i.e. scoping, designing, permitting, pre-construction, construction, and completion/de-energization), where appropriate.[171] For consistency in reporting across the Subproject Table (C.14) and the SPM Template, we use the same Subproject milestones listed in the "status_current" field of the Subproject Table (C.14) for the SPM Template.

PG&E will update the SPM Template for each Progress Report as new Subprojects are added to the Portfolio and if dates change for existing Subprojects.

Table C.23 is submitted with Progress Report 0 and each subsequent Progress Report.

b) Assumptions and Limitations

The SPM Template milestones differ from those required in EUP Guidelines Section 2.5.1 and the Undergrounding Project lifecycle phases described in Chapter 4, Section D.1.b. In

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[170] The EUP Guidelines require a Project Management Template. PG&E plans to report undergrounding work in this template at the subproject level, a more granular view than the project-level, PG&E renamed this template to be clear on the level of detail provided in this report.

[171] An explicit pre-construction milestone is not included in the SPM template as pre-construction milestones are considered the same as all milestones prior to construction, including scoping, planning and design, permitting and dependencies.

Chapter 5, Table 5-3, PG&E maps the SPM Template milestones to these fields.

18) List of Fire Rebuild Area Table (Table C.24)

a) Table Description

PG&E provides a supplementary table (Table C.24) to the Progress Report containing a list of Fire Rebuild Areas, including the wildfire date, time, location, affected Circuit Segments and facilities impacted. This table identifies whether there is completed or ongoing Fire Rebuild work associated with the wildfire event. This table is provided to satisfy requirements outlined in EUP Guidelines Section 2.4.3.1.

b) Assumptions and Limitations

PG&E does not maintain a comprehensive inventory of all wildfire events occurring within our service territory, nor the facilities and Circuit Segments impacted by those incidents. To comply with the requirements of Section 2.4.3.1 of the EUP Guidelines, PG&E provides a list of wildfire events associated with current or historical (2015-2025) Fire Rebuild work. Because the underlying historical data sources are not comprehensive, the information presented in this table may not reflect all wildfire events or associated impacts within PG&E's service territory.

PG&E’s records do not consistently include wildfire name, date, and location data for every wildfire event in our service territory. Accordingly, for consistency in producing this table, we are relying on CAL FIRE’s records, where available, to provide wildfire name, date, and locations. If a wildfire event cannot be identified with a CAL FIRE record, the Wildfire event is reported with an unknown date or location information.

Circuit Segments reported within this table are limited to Circuit Segments which are named within the most recent WDRM. This ensures that only Circuit Segments which are reported in Table C.6 are reported in this table. Facilities data is

reported as a count of unique assets identified within the historical Fire Rebuild Area dataset.

PG&E repairs or replaces distribution infrastructure after a wildfire as needed to provide safe and reliable service for our customers. Not all repair or replacement work requires system hardening. For the Rebuild Status field in Table C.24, the status of rebuild work in Fire Rebuild Areas is provided. The status of rebuild work for wildfire areas that do not have associated system hardening work and/or is not in Fire Rebuild Areas is designated as "N/A."

c. JSON Data Submissions (EUP Guidelines Section 2.8.2, and Appendix C.2)[172]

The Large Electrical Corporation must submit the following JSON data in each Progress Report, including Progress Report 0:

a. A Project Variable Modifiers JSON as described in Section 2.8.5.2 and Appendix C of these Guidelines.

b. A Model Risk Landscape JSON, as described in Appendix C of these Guidelines, with information for each project that has passed Screen 3.

These files must reflect the most current information as of each Progress Report submission. Further details on JSON submissions are in Section 3.11 of these Guidelines and in Appendix C.

The Large Electrical Corporation must convert its JSON data submission into Comma Separated Values (CSV) format and host the CSV files on a publicly available webpage dedicated to its EUP, as described in Section 3.8.1 of these Guidelines.

PG&E's JSON Data Submission[173] includes: (1) Project Variable Modifiers as described in the EUP Guidelines Section 2.8.5.2; and (2) a

[172] PG&E is including in this chapter narratives regarding our JSON Data Submissions, Spatial Data Submissions and GIS data Schema to respond to the requirement in EUP Guidelines Section 2.6.1 i. to address "[a]ll data required pursuant to Section 2.8 and Appendix C of these Guidelines" and address all requirements in Appendix C in this Chapter. These requirements are also indicated to be included in Chapter 9 pursuant to Section 2.8 of the EUP Guidelines. To avoid duplication, PG&E is submitting this discussion only in this chapter and is cross referencing this discussion in Chapter 9.

[173] JavaScript Object Notation or JSON "is a data file type designed to track unstructured data that would not be appropriate for a spreadsheet format." EUP Guidelines, p. A-3.

Model Risk Landscape Variables for all Projects that have passed Screen 3 as described in EUP Guidelines Section 2.8.5.1.

We will provide the JSON data that is required in the EUP Guidelines Appendix C, Section C.2. This consists of two JSON files: one for the Project Variable Modifiers and one for the Model Risk Landscape (pre- and post-mitigation KDMM values). These files will contain all data relevant to the reporting of separate, ablation, and collective study 'settings' for each mitigation type for each Project_ID, per the requirements in the EUP Guidelines Appendix C, Section C.2.2.

JSON files will be submitted as an e-filing. Additionally, PG&E will convert the JSON files to CSV files and host them on a publicly-available webpage dedicated to our EUP (www.pge.com/eup). PG&E's tabular data including Tables C.1 – C.15, C.22 – C.24, can be found in Attach. A-2, and the JSON Data Submission can be found in Attach. A-3 and A-4.[174]

The JSON data is submitted with Progress Report 0 and each subsequent Progress Report.

d. Spatial Data Submissions (EUP Guidelines, Section 2.8.3, and Appendix C.3)

The Large Electrical Corporation must report additional modeling and Project-Level data through a geodatabase submission. This information will identify isolatable Circuit Segments, Undergrounding Projects, overhead lines that will be deenergized after completion of projects, and critical pieces of infrastructure equipment. The Large Electrical Corporation must update information reported in geodatabase submissions in each Progress Report.

Further details about these submissions are found in Appendix C.3.

We will report additional modeling and Project-Level data through a geodatabase submission that identifies isolatable Circuit Segments, Undergrounding Projects, overhead lines that will be deenergized after completion of a Project, and critical pieces of infrastructure equipment.

[174] See JSON Project Variable Modifiers (Attach. A-3) and JSON Model Risk Landscapes for Projects (Attach. A-4).

We also will provide the geospatial data that is required in EUP Guidelines Appendix C, Section C.4 in the form of a Geodatabase (GDB)[175] using the template available on the Energy Safety website. We will submit an updated GDB using the most recent available template with each Progress Report and we will maintain an archive of all previously submitted Progress Report GDB files.

Each GDB submission will include the six features described in the EUP Guidelines. PG&E's spatial data including Tables C.16 – C.21, can be found in Attach. A-5, GIS Data Schema. Our data sources for the separate features are described below.

The spatial data is submitted with Progress Report 0 and each subsequent Progress Report.

e. Geographic Information System Data Schema (EUP Guidelines, Appendix C.4)

1) Circuit Segment (Line Feature Class) (GIS Feature C.4.1)

We will provide all primary and secondary (where available) electric distribution lines included in the most recent risk model version including overhead and underground circuit geometry. Data will be provided as a single polyline feature. In Progress Report 0, the relevant risk model version will be 'WBCA_v1c0', and the geometry will be based on WDRM v4, the most current 'snapshot' of the electric distribution system from January 1, 2023. The Circuit Segment geometry will remain the same until the risk model is updated, as Circuit Segment names and geometry are defined using the distribution system snapshot used in the risk model. Each record in this feature will match one and only one row of the Circuit Segment Identification Table (C.6).

2) Circuit Segment GIS Data (Table C.16)

Table C.16 is the attribute table of the Circuit Segment Geographic Information System (GIS) Feature. It will include the Utility Name, Plan ID, Circuit Segment, and Circuit Segment ID for

[175] A geodatabase is a collection of geographic datasets of various types held in a common file system folder, or a multiuser relational database management system.

every circuit segment in the most current risk model. PG&E makes no distinction between Circuit Segment ID and Internal Circuit Segment ID: the Internal Circuit Segment ID field will always be NULL.

f. Confirmed Project Polygon (Polygon Feature Class) (GIS Feature C.4.2)

For each Project we will create a Project Polygon feature based on the Circuit Segment that Project was defined on. Generally, each Project will be associated with one Circuit Segment in the GIS data, and the Project Polygon will include the Circuit Segment geometry. We will avoid overlap between crossing or adjacent Circuit Segments where possible, but some overlap may be unavoidable, as in cases where circuit segments intersect or are in close, parallel alignment. The Project Polygons will encompass the pre-mitigation geometries of the constituent Subprojects.

1) Project GIS Data (Table C.17)

Table C.17 is the attribute table of the Project Polygon GIS feature. We will include the Utility Name, Project ID, Plan ID, Portfolio ID, Circuit ID, Circuit Segment ID, and Circuit Segment Vintage from Table C.10 Project Table. Each Project Polygon will correspond to a single row in this table.

g. Pre-Mitigation Overhead Conductor (Line Feature Class) (GIS Feature C.4.3)

Geometry will be a polyline based on the current Subproject scope at the time the Progress Report is submitted. All overhead conductor that will be replaced with overhead covered conductor, removed, or replaced with underground conductor will be represented in this feature. If the original scoped geometry is updated, we will provide an updated pre_mitigation_alignment_id which will map to the Subproject Table. Pre_mitigation_alignment_id will start at 0 and increase if and when the endpoints of available geospatial data move. Pre-Mitigation geometry is expected to always fall within the Project Polygon. In the event that a Subproject's Pre-Mitigation Geometry falls outside the bounds of the

associated Confirmed Project Polygon, we will provide an explanation in Table C.14 for that Subproject.

1) Pre-Mitigation Overhead Conductor GIS Data (Table C.18)

Table C.18 is the attribute table of the Pre-Mitigation Overhead Conductor GIS feature. It will contain the Utility Name, the Subproject ID on which the Overhead Conductor geometry is based, the version of the Overhead Conductor Geometry (the Pre-Mitigation Alignment ID Field), the Plan ID, Project ID, Circuit ID, and Circuit Segment ID that the Subproject is associated with. This table will also identify the class of conductor that is selected for mitigation as overhead or underground, and primary or secondary, in the Line Class field. PG&E will update the information in this data table any time the endpoints of the geometry of the Pre-mitigation Overhead Conductor GIS feature change.

h. Pre-Mitigation Assets (Point Feature Class) (GIS Feature C.4.4)

Pre-mitigation overhead conductor geometries are based on scoping or design drawings that are created in a different system than GIS (PG&E system of record). As such, they will not be perfectly aligned with existing mapped Circuit Segment geometry. Therefore, we will use a buffer analysis that relies on the Subproject's Pre-mitigation Overhead Conductor line feature data to capture assets within a 24-foot buffer, or within 12 feet of that conductor geometry in any direction. This is the optimal extent for capturing all relevant assets while minimizing the capture of assets not associated with the Subproject's geospatial scope. This data must be regarded as a close approximation of the pre-mitigation assets in scope and may capture assets that belong to parallel or adjacent circuit segments. PG&E does not currently attribute the assets with their Circuit Segment in the GIS system of record.

1) Pre-Mitigation Assets GIS Data (Table C.19)

Table C.19 is the attribute table of the Pre-Mitigation Assets GIS feature. It contains the Utility Name, Subproject ID, Project ID, Plan ID, Portfolio ID, Circuit ID, and Circuit Segment ID that an individual asset data point is associated with via the geospatial analysis

described above. This table will also be updated with the pre- mitigation alignment id (geometry version) of the affiliated Subproject. This table will identify the asset type of each data point including: capacitor bank, fuse, switchgear, transformer, or support structure. Assets will be associated with a single Subproject ID. This table is submitted as confidential due to the identification of utility infrastructure locations.

i. Post-Mitigation Conductor (Line Feature Class) (GIS Feature C.4.5)

We will show the extent of the future planned underground and covered conductor installation. In some cases, this geometry will extend beyond the extent of the confirmed Project Polygon because the future planned underground and covered conductor installation does not always align with the planned Project Polygon. PG&E will update the information in this data table any time the endpoints of the geometry of the post-mitigation conductor GIS feature change. At a minimum, this will include the update from scoped post-mitigation conductor alignment, to actual post-mitigation conductor alignment, which will be provided when all mitigation work on a given Subproject has been completed and mapped.

1) Post-Mitigation Conductor GIS Data (Table C.20)

Table C.20 is the attribute table of the Post-Mitigation Overhead Conductor GIS feature. It will contain the Utility Name, the Subproject ID on which the post mitigation geometry is based, the version of the post-mitigation geometry (the post Mitigation Alignment ID Field), the Plan ID, Project ID, Circuit ID, and Circuit Segment ID that the Subproject is associated with. This table will also identify the class of conductor that is planned or installed as overhead or underground, and primary or secondary, in the Line Class field. PG&E will update the information in this data table any time the endpoints of the geometry of the post-mitigation Overhead Conductor GIS feature change. Table C.20 will be provided as soon as a Subproject's geometry is scoped and will be updated at least one time when the Subproject's geometry is fully mapped in PG&E's

GIS system of record based on the actual work completed for that Subproject.

j. Post-Mitigation Assets (Point Feature Class) (GIS Feature C.4.6)

Post-mitigation assets including transformers, switches, fuses, and capacitor banks can be drawn in the scoping phase and will be provided for Subprojects when geometry is first provided. However, poles are not identified in the scoping phase and will not be included in this feature until all PG&E work on a Subproject has been completed and mapped in the GIS system of record. PG&E does not expect to update this feature between the scoping phase and the mapping of the Subproject.

1) Post-Mitigation Assets GIS Data (Table C.21)

Table C.21 is the attribute table of the pre-mitigation assets GIS feature. It contains the Utility Name, Subproject ID, Project ID, Plan ID, Portfolio ID, Circuit ID, and Circuit Segment ID that an individual asset data point is associated with via the initial scoping drawing (if the Subproject has not been fully mapped), or the GIS system of record (if the Subproject has been fully mapped). This table will also be updated with the post-mitigation alignment id (geometry version) of the affiliated Subproject. This table will identify the asset type of each data point, including: capacitor bank, fuse, switchgear, transformer, or support structure. Asset type data for capacitor banks, fuses, switchgears, and transformers will be available after a Subproject has been scoped; however, the post mitigation support structure asset data will not be available for a Subproject until it has been fully mapped in the GIS system of record. Assets will be associated with a single Subproject ID. This table is submitted as confidential due to the identification of utility infrastructure locations.

2. Relation of Progress Report 0 to Statutory Progress Report Requirement (EUP Guidelines Section 2.6.2)

The content, format, and structure of Progress Report 0 will inform the requirements for future Progress Reports. Energy Safety may provide additional guidance regarding future Progress Report requirements at a later date.

We understand that the content, format, and structure of Progress Report 0 will inform the requirements for future Progress Reports and that Energy Safety may provide additional guidance regarding future Progress Report requirements. We will respectfully request sufficient time to implement any new requirements.

D. Chapter Summary

In this chapter, PG&E describes the content, structure, and rationale for Progress Report 0 to demonstrate how it satisfies the requirements of SB 884 and EUP Guidelines Sections 2.6, 2.6.1, 2.6.2, and Appendix C. This chapter explains how Progress Report 0 integrates narrative discussion, tabular data, JSON submissions, and spatial datasets to provide a comprehensive and transparent snapshot of program status, risk modeling, Project selection, and implementation planning at the time of EUP submission. Together, these elements establish a consistent reporting framework that supports regulatory review, enables tracking of progress over time, and provides the foundation for future semiannual Progress Reports as PG&E advances implementation of the EUP.

E. Chapter 6 Supporting Attachments Index

The following attachments outlined in Table 6-4 support this chapter:

TABLE 6-4:
CHAPTER 6 SUPPORTING ATTACHMENTS/WORKPAPERS INDEX

Line No.	EUP Section	EUP Location	Workpaper / Table Name	File Name
1	6.C.1.a	Attachment A	Progress Report 0 Narrative	PGE_AtchA_2026-~~09~~10-30_Progress Report 0 Narrative_R0
2	6.C.1.a	Attachment A-1	Progress Report 0 Portfolio Coversheet	PGE_AtchA1_2026-~~09~~10-30_Progress Report 0 Portfolio Coversheet_R0
3	6.C.1.b 6.C.1.c	Attachment A-2	Progress Report Tabular Data Submission	PGE_Initial_ 2026-~~09-30~~11-02_Tabular Data_R0
4	6.C.1.c	Attachment A-3	JSON Data Submission: Project Variable Modifiers	PGE_Initial_2026-09-30_PMV_R0
5	6.C.1.c	Attachment A-4	JSON Data Submission: Model Risk Landscapes for Projects	PGE_Initial_ 2026-~~09~~10-30_Projects_R0
6	6.C.1.d	Attachment A-5	Spatial Data Submission	PGE_Initial_ 2026-09-30_GIS Data_R0_CONF
7	6.C.1.a	Attachment D	SPD-37 Appendix 1 Data Submission	PGE_Initial_ 2026-~~09-30~~11-02_Attachment D_R0

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 7

RISK MODELING METHODOLOGY

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 7
RISK MODELING METHODOLOGY

A. Chapter Introduction

This chapter explains Pacific Gas and Electric Company's (PG&E) Risk Modeling Methodology consistent with the requirements in Section 2.7 of the Electrical Undergrounding Plan (EUP) Guidelines.

Section B lists the requirements in Senate Bill (SB) 884 and the EUP Guidelines addressed in this chapter.

Section C summarizes PG&E's Risk Modeling Methodology. PG&E's Risk Modeling Methodology consists of our Wildfire Distribution Risk Model (WDRM), Outage Program Risk Model (OPRM), Enterprise Bow Tie Model, and Wildfire Benefit-Cost Analysis (WBCA) model. The WDRM, OPRM, and WBCA are supported by several sub-models.[176]

The WDRM identifies the highest Wildfire Risk on PG&E's distribution system by estimating Circuit-Segment-Level Ignition Likelihood and potential wildfire consequences. The outputs from the WDRM and OPRM, along with cost, benefit, mitigation effectiveness and financial inputs are used in the WBCA to calculate Benefit-Cost Ratios (BCR) for a variety of system hardening mitigations at the Circuit Segment level. In parallel, the OPRM quantifies the reliability impacts associated with wildfire mitigation outage programs by estimating the likelihood and customer impacts of Enhanced Powerline Safety Settings (EPSS) and Public Safety Power Shutoff (PSPS) events. Together, these models provide a view of wildfire risk and reliability impacts across the system.

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[176] These four key models describe PG&E's overall risk modeling methodology. The seven model chapters outlined in Sections D.1 to D.7 below provide the required model-by-model detail underlying the risk modeling methodology, this includes models that are inputs to the key models. WDRM is documented through separate Ignition Likelihood and Ignition Consequence chapters (Model Report Chapters 1 and 2); OPRM is documented through separate EPSS and PSPS chapters (Model Report Chapters 3 and 4); and the remaining chapters explain the Overall Utility Risk calculation (Model Report Chapter 4), the WBCA (Model Report Chapter 5), and the Enterprise Bow Tie Model (Model Report Chapter 6).

Section D includes Model Reports for each of the risk models in the Risk Modeling Methodology. There is a Model Report for the Ignition Likelihood Model (Section D.1), Ignition Consequence Model (Section D.2), OPRM: EPSS (Section D.3), OPRM: PSPS (Section D.4), Overall Utility Risk Model (Section D.5), WBCA (Section D.6), and the Enterprise Risk Bow Tie Model (Section D.7).

Section E discusses the Key Decision-Making Metrics (KDMM) that PG&E will use to evaluate the efficacy of Undergrounding Projects.

Section F discusses the core capabilities for our Risk Modeling Methodology.

Section G discusses the Core Capabilities for risk modeling and provides enterprise diagrams for each of the risk models.

Sections H through N discuss various model requirements including version and calibration changes, Project Variable Modifiers, Portfolio-Level Standards, Project-Level Thresholds, and Comparative Metrics.

Section O responds to comments by the California Public Utilities Commission's (CPUC or Commission) Safety Policy Division and intervenors on PG&E's Risk Assessment and Mitigation Phase (RAMP) Report.

Section P provides a brief chapter summary and Section Q lists appendices that support this chapter.

B. Undergrounding Plan Requirements

In Tables 7-1 and 7-2 below, we identify each of the statutory and EUP Guidelines requirements that are addressed in this chapter.

TABLE 7-1:
SB 884 REQUIREMENTS ADDRESSED IN CHAPTER 7

Line No.	Public Utilities Code Section	Legislative Requirement	Where Requirement is Addressed
1	8388.5(d)(2)	The office [Office of Energy Infrastructure Safety] may only approve the plan if the large electrical corporation has shown that the plan will substantially increase electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and substantially reduce the risk of wildfire.	Chapter 7

TABLE 7-2:
EUP GUIDELINES REQUIREMENTS ADDRESSED IN CHAPTER 7

Line No.	EUP Guidelines Section	EUP Guidelines Requirements	Requirement Reference in Chapter 7
1	2.7	Risk Modeling	Section C
2	2.7.1	Overview of Risk Modeling Methodology	Section C.1
3	2.7.2	Model Reports	Section D
4	2.7.3	Key Decision-Making Metrics and Enterprise Diagrams	Section E
5	2.7.3.1	Enterprise Diagram	Section E.1
6	2.7.4	Model Risk Landscape	Section F
7	2.7.5	Required Core Capabilities for Risk Modeling Methodology	Section G
8	2.7.5.1	Model Inputs and Considerations	Section H
9	2.7.5.2	Version and Calibration Changes	Section I
10	2.7.6	Model Retention and Update Schedule	Section J
11	2.7.7	Project Variable Modifiers (PVM)	Section K
12	2.7.8	Portfolio-Level Standards	Section L
13	2.7.9	Project-Level Thresholds and Standards	Section M
14	2.7.9.1	Project-Level Thresholds	Section M.1
15	2.7.9.2	Project-Level Standards	Section M.2
16	2.7.10	Comparative Metrics	Section N

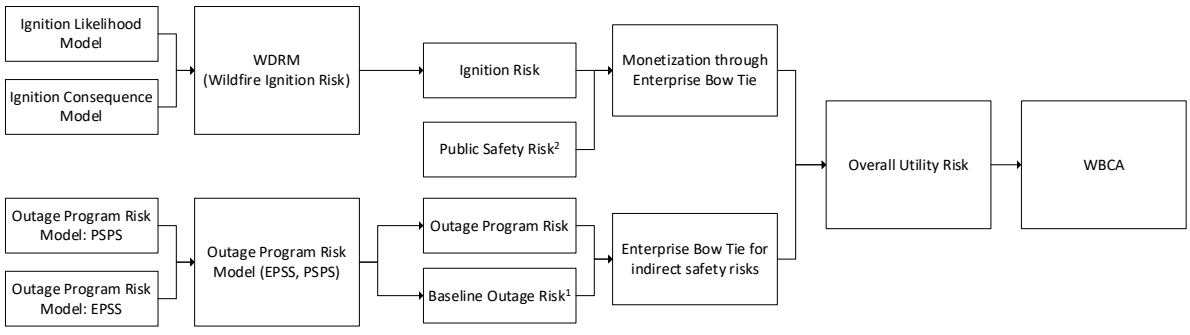
C. Risk Modeling (EUP Guidelines Section 2.7)

This section describes the requirements for the Risk Modeling Methodology that the Large Electrical Corporation must employ to establish the Plan Mitigation Objective and to perform the analysis required in Screen 3 (Project Risk Analysis).

The Large Electrical Corporation must justify its methodology in a narrative section of its EUP submission.

We use our risk models to conduct analyses of Project-Level Risk and Ignition Risk. We conduct these analyses separately and look at them collectively to prioritize the locations and best mitigations for system hardening projects. Our risk modeling methodology enables us to estimate future risks and accumulation of risk over time, account for Undergrounding Projects with multiple mitigations and Subprojects, establish Baselines and historical calibrations, and compare Alternative Mitigation strategies. This integrated approach allows PG&E to make consistent, quantitative, and risk-informed decisions about undergrounding and Alternative Mitigations across our system. Figure 7-1 below is a high-level summary of the relationships between the key risk models.

FIGURE 7-1:
RISK MODEL SUMMARY AND RELATIONSHIPS



1. Baseline Outage Risk is a component of the Outage Program Risk Model, specifically the EPSS model. Baseline Outage Risk includes indirect safety risks.
2. Public Safety Risk data is not derived from a risk model, it is based on historic actual events.

1. Overview of Risk Modeling Methodology (EUP Guidelines Section 2.7.1)

The Large Electrical Corporation must provide an overview narrative that explains the key elements of its risk modeling approach and definitions. The narrative must detail how the Large Electrical Corporation will compare the potential wildfire risk and reliability impacts of Undergrounding to Alternative Mitigations. The overview must describe the methodology and underlying intent of the Large Electrical Corporation's risk assessment in no more than five pages, inclusive of all narratives, bullet point lists, and any graphics. The overview narrative should also include any additional Key Decision-Making Metrics (KDMMs) proposed by the Large Electrical Corporation and the enterprise diagram as required by Section 2.7.3 below.

a. PG&E's Risk Assessment Methodology and Underlying Intent

As summarized in Figure 7-1 above, PG&E's risk assessment methodology begins with the quantification of Baseline risk across the electric distribution system. This Baseline risk is estimated using a combination of bottom-up risk models that together provide both spatial detail and enterprise-level valuation.

At the Circuit Segment level, the WDRM and OPRM estimate where risk is concentrated by assessing Wildfire and Reliability Risk across the system. Additional detail regarding the methodologies and algorithms underlying these models is provided in the RaDA Algorithms and Methodologies Whitepaper (Attach. B. WP0023). At the enterprise level, the Enterprise Bow Tie Model translates these risks into monetized impacts. Together, these models provide a view of where risk is concentrated and the magnitude of potential impacts.

To assess wildfire and safety risk impacts, PG&E uses historic acres burned, structures destroyed, loss of life and serious injuries, and California Department of Forestry and Fire Protection (CAL FIRE) suppression data to value the wildfire risk associated with the electric system. To assess reliability risk impacts, PG&E uses Lawrence Berkeley National Laboratory's (LBNL) Interruption Cost Estimate (ICE) calculator to monetize the impact of outages on customers.[177]

[177] Resolution SPD-37 (Dec. 10, 2025).

Once Baseline monetized risk is established, PG&E uses the WBCA to evaluate Alternative Mitigations for high-risk Circuit Segments. The WBCA applies mitigation-specific effectiveness values to estimate the amount of risk each mitigation is expected to reduce over its lifetime. These estimated risk reduction benefits are then compared to lifetime costs to support quantitative, risk-informed selection of preferred mitigation solutions.

This integrated approach allows PG&E to prioritize mitigation investments based on their ability to deliver meaningful risk reduction in a cost-effective manner, while recognizing that different locations, asset conditions, and risk drivers may warrant different mitigation solutions.

b. PG&E's Risk Models and Risk Model Landscape

PG&E's EUP Model Risk Landscape consists of the: (1) WDRM; (2) OPRM; (3) WBCA; and (4) Enterprise Bow Tie Model. Together, these models quantify Baseline risk, translate risk into monetized impacts, and evaluate mitigation alternatives to support risk-informed decision making. The enterprise diagrams are provided in Section E below. In the Model Reports below, PG&E describes the vintage of the models and plans to update the models. PG&E retires prior versions of the risk models after an update. However, the model update does not invalidate the prior model version or the planning and risk-informed decisions that were based on that model version.

1) WDRM

The WDRM produces relative Circuit Segment values for Ignition Risk (also referred to as Wildfire Risk, defined as the product of Ignition Likelihood of a Risk Event (LoRE) and Ignition Consequence of Risk Event (CoRE). Ignition Likelihood represents the expected count of ignitions during wildfire season (June through November) based on asset-specific failure modes and Ignition Consequence represents the expected impact based on calibrated wildfire spread simulations. Detailed descriptions are provided in Sections D.1 and D.2.

Ignition Risk and Ignition Likelihood at the Circuit Segment level are calculated by aggregating the corresponding results across all asset locations within a Circuit Segment. Circuit Segment consequence is calculated as a probability-weighted average, such that locations with a higher likelihood of ignition contribute more, reflecting the consequence most relevant to where ignitions are most likely. The Circuit Segment Consequence is derived by dividing Circuit Segment Ignition Risk by Circuit Segment Ignition Likelihood.

The WDRM produces a static baseline wildfire season dataset aligned to a defined system configuration until a new version is produced. WDRM version 4 (WDRM v4), based on a January 1, 2023 configuration, produces outputs at the asset, pixel, composite, and Circuit Segment levels. Circuit Segment Ignition Risk, Ignition Likelihood, and Ignition Weighted Consequence are used to prioritize mitigation, inform Ignition Tail Risk thresholds, and serve as direct inputs into the Circuit Segment Overall Utility Risk value. Additional details are provided in Attach. B, WP026.

2) OPRM

The OPRM produces three distinct Circuit Segment-level outputs: (1) EPSS Risk, (2) PSPS Risk, and (3) Baseline Outage Risk. EPSS Risk and PSPS Risk represent outage impacts directly attributable to these programs and are combined to calculate Outage Program Risk, consistent with the EUP Guidelines. Detailed descriptions of the EPSS and PSPS models are provided in Sections D.3 and D.4 below.

Outage Program Likelihood is calculated as the sum of EPSS and PSPS Likelihood, and Outage Program Risk as the sum of EPSS Risk and PSPS Risk. The Outage Program Likelihood is used to establish the High Frequency Outage Program Threshold, which identifies additional Circuit Segments with significantly elevated likelihood of frequent or prolonged service disruptions. Outage Program Consequence is derived by dividing Outage Program Risk by Outage Program Likelihood.

EPSS Outage Likelihood estimates the expected incremental annual outage duration (in minutes per year) from enabling EPSS. EPSS Outage Consequence quantifies the expected cost (in dollars) of a Circuit Segment outage based on the number of affected customers and Value of Service (VoS).

PSPS Outage Likelihood estimates the expected annual outage duration (in minutes per year) based on a Circuit Segment's historical exposure to PSPS events. Circuit Segment PSPS exposure is determined by a combination of PSPS event data and a historical lookback analysis that applies current PSPS criteria to past weather conditions. Outage Consequence represents the total expected cost (in dollars) of outages attributed to a Circuit Segment, including both direct and downstream customer impacts.

Baseline Outage Risk represents residual risk of sustained outages not attributable to EPSS or PSPS, i.e., outage impacts that would be expected to occur absent these wildfire mitigation programs. While EPSS Risk, PSPS Risk, and Baseline Outage Risk are all incorporated into the WBCA to capture total customer outage impacts, only EPSS Risk and PSPS Risk are included in the Outage Program Risk KDMM and Overall Utility Risk KDMM used to inform mitigation selection decisions.

The OPRM version 1 (v1) [178] produces a static dataset of Circuit Segment Outage Risk aligned to the same defined system configuration as WDRM v4. Model inputs are described in Section H.2 and Attach. B, WP019 (See Sections D.3 and D.4.for additional details.)

PG&E uses the WBCA to perform Circuit-Segment-level evaluations of Alternative Mitigations and Additional Comparisons within the Project Acceptance Framework. The WBCA quantifies and compares the costs and benefits of each mitigation, including capital (construction) costs, ongoing operations and maintenance

[178] The underlying data of the OPRM is based on a data vintage date of January 1, 2023. The PSPS Risk Model also includes PSPS customer and event data from the 2024 PSPS lookback study, which is the most recent PSPS lookback study available.

(O&M) costs, projected climate change impacts, public safety benefits, Wildfire Risk reduction, and reliability improvements.

WBCA version 1 (data as of January 2026) integrates output from the WDRM and OPRM with inputs described in the WBCA documentation (Attach. B, WP006) to calculate BCRs for each mitigation evaluated in Screen 2. These mitigation configurations include: (1) 100 percent Undergrounding, (2) 100 percent Overhead Hardening, (3) 100 percent Remote Grid, and (4) hybrid configurations (50 percent undergrounding/50 percent overhead hardening).

The WBCA estimates total wildfire, reliability, and safety risk reduction over the expected life of each asset using monetized risk values derived from WDRM and OPRM, supplemented by inputs from the Enterprise Bow Tie Models. PG&E assumes asset lives of 55 years for undergrounding and 48 years for overhead hardening. The resulting lifetime risk reduction is compared to total lifecycle costs relative to the No-Build Baseline[179] are used to calculate Project BCRs.

Assumptions and inputs are further refined during the Screen 3 scoping process (see Chapter 3, Section D.3), to support more detailed comparisons of Alternative Mitigations and identification of the appropriate system hardening strategy for each Circuit Segment. The use of model outputs in these evaluations is described in Chapter 3, Sections D.2 (Screen 2) and D.3 (Screen 3), consistent with EUP Guidelines Sections 2.4.4 and 2.4.5.

3) Enterprise Bow Tie Model

The Enterprise Risk Bow Tie Model serves as the top-down component of PG&E's Model Risk Landscape, converting ignition and outage-related risks into enterprise risk values used in downstream analysis. The model consists of three integrated Bow Tie models: a Wildfire Bow Tie, a PSPS Bow Tie, and an EPSS Bow Tie. For brevity, the discussion below focuses primarily on the

[179] See Attach. B, WP006 for further details.

Wildfire Bow Tie. The model is developed under PG&E's standardized Bow Tie methodology consistent with the CPUC Risk- Based Decision-Making Framework (RDF).[180]

The model integrates historical ignition and outage data, post-event observations such as PSPS hazards and damages, and external data sources (e.g., CAL FIRE records), along with monetization parameters such as the Value of Statistical Life (VSL) and VoS to quantify safety and reliability impacts in dollar terms.

Using these inputs, the model estimates event frequency by combining observed ignitions with avoided ignitions attributable to mitigation programs, allocates frequency across outcome categories using conditional probabilities, and characterizes consequences across safety, reliability, and financial attributes. These consequences are expressed in natural units (equivalent fatalities, customer minutes interrupted, and dollars), monetized, and aggregated into a single consequence value (CoRE), which is combined with frequency to calculate annual risk.

The Enterprise Bow Tie Model produces standardized enterprise-level outputs, including expected annual frequency, expected consequences by attribute, and risk values expressed in both risk-neutral and risk-adjusted dollars.[181] These risk-adjusted dollars are used as the quantified risk values in WBCA BCR calculations and provide the monetized risk foundation that integrates with WDRM and OPRM outputs.

2. Key Decision-Making Metrics

PG&E is using the KDMMs required by EUP Guidelines Section 2.7.3 as discussed in Section E. PG&E is not proposing any additional KDMMs.

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[180] Decision (D.) 22-12-027, Appendix A – Risk-Based Decision-Making Framework.

[181] ICE Calculator is required as outlined in D.22-12-027, Appendix A, p. A-8, Step 1A, Rows 6-7.

D. Model Reports (EUP Guidelines Section 2.7.2)

The Large Electrical Corporation must present a Model Report consisting of a collection of report chapters on each individual model used in the Risk Modeling Methodology. A model is defined as a distinct part of the larger Risk Modeling Methodology that has explainable units. These distinctions must be at least as granular as in the enterprise diagram described in Section 2.7.3.1 of these Guidelines. At a minimum, these models must include an Ignition Likelihood model, an Ignition Consequence model, an Outage Program likelihood model, an Outage Program consequence model, and an overall utility risk model. For each model, the Large Electrical Corporation must describe the methodology and numerical calculations involved at a level of detail that would allow for verification and replication in a self-contained chapter. Each chapter of the Model Report must be no more than four pages, inclusive of all narratives, bullet point lists, and any graphics. A Model Report may reference additional, publicly available documents published by the Large Electrical Corporation or third-party vendors. Each Model Report must also attach a technical workbook as an appendix. The technical workbook must demonstrate the numerical calculations and contain the toy problems referenced below.

Each chapter of the Model Report must be formatted into the following subsections addressing different aspects of the modeling methodology and implementation.

a. ***Model Usage:*** *For each chapter, the Model Usage section must describe the model's scope, how often the model is utilized, what aspects of the electrical system's risk profile are evaluated by this model, and specifically identify what risk or risk component the model is evaluating.*

b. ***Model Type:*** *For each chapter, the Model Type section must describe the model's taxonomy (e.g., physics simulation, mathematical model, machine learning classification).*

c. ***Key Inputs:*** *For each chapter, the Key Inputs section must describe the data that is fed into a calibrated model, including a description of the original data collection when applicable.*

d. ***Model Solution:*** *For each chapter, the Model Solution section must describe the method used to calibrate, train, simulate, optimize, or implement the model from a mathematical standpoint. The model solution must include relevant information. For example:*

   i. *If the model is based on a historical frequency table, briefly describe the data procurement and weighting of the decision function.*

   ii. *If the model is based on a general linear model, Bayesian regression or other under-parameterized model, describe the training data and validation accuracy of the model.*

   iii. *If the model is based on solving a non-convex problem, briefly describe the optimization procedure and potential pitfalls of local minima.*

iv. *If the model is based on an overparameterized network, briefly describe the optimization procedure, including the number of learnable parameters, training technique, and the size and origin of the training and testing sets.*

v. *If the model is based on a physical simulation, describe the simulation evolution algorithm, spatial and temporal resolution, and any subgrid effects considered.*

vi. *If the model is based on Monte Carlo simulations, describe the assumptions made to build the component distributions and the outcome uncertainties*

e. ***Model Outputs**: For each chapter, the Model Outputs section must describe how the data produced by the model is fed into other models or used by the Large Electrical Corporation to make risk-related decisions. The Large Electrical Corporation must describe the mathematical type of output (e.g., distribution, average value, score, probability), the spatial resolution (e.g., per Circuit, per segment, per county) and temporal resolution (e.g., per day, per season, per year).*

f. ***Uncertainty:** For each chapter, the Uncertainty section must describe the amount by which a calculated value output by the model might differ from the actual value when the input parameters are known. Additionally, this section must address any methods the Large Electrical Corporation uses to account for missing input data in its Risk Modeling Methodology. Lastly, this section must address the sensitivity analysis used to determine the relationships between the uncertainty in the inputs used in an analysis and the uncertainty in the resultant dependent variables due to numerical instability or stiffness of the underlying equations.*

g. ***Toy Problems**: For each chapter, the Toy Problems section must describe three examples, specifying input and output values, using synthetic data. One input must lead to a low-risk (or low-probability, low-consequence) output, one for a medium-risk case, and one for a high-risk case. In each case, the Large Electrical Corporation must describe the magnitude and units of the inputs and outputs as well as the prevalence of each scenario in real-world data. These examples must also be presented numerically in a workbook attached to the end of the Model Report.*

h. ***Shelf-Life:** For each chapter, the Shelf-life section must describe the length or period the model is expected to be used. This section must describe if/how the model is expected to be updated, both regarding new calibration data and new project input data. This section must describe if/when the model is expected to be retired or replaced by an entirely new model. Sections 2.7.5.2 and 2.7.7 of these Guidelines detail further requirements for updating the Risk Modeling Methodology.*

In this section, PG&E presents a model report that consists of chapters on each of the individual models used in our Risk Modeling Methodology. Each model report describes the methodology and numerical calculations at a level of detail that allows for verification and replication. Due to page limitations for this

section, PG&E also refers the reader to the relevant sections of the model documentation for additional detail.

PG&E has taken a “bootstrapping” approach to uncertainty for most model reports, as discussed in subsection f of each Model Report Chapter below. This approach involves repeatedly resampling the Circuit Segment level value from the risk model, with replacement, computing the statistic of interest for each resample. The computed values for the statistic form an estimate of the sampling distribution of the statistic. The 95 percent confidence interval is then taken as the 2.5th and 97.5th percentiles of this bootstrap distribution. Models that use alternative uncertainty methodologies are described separately in their respective chapters.

1. Model Report Chapter 1 – Ignition Likelihood Model

PG&E’s Ignition Likelihood Model for the WDRM is implemented through the Distribution Event Probability Models (DEPM), which is comprised of 23 cause-specific Probability of Outage models and a final Probability of Ignition Given Outage model. The DEPM v4 documentation provided as Attach. B, WP015 describes the model types, key inputs, model solutions, and outputs for these 23 models.

a. Model Usage

The Ignition Likelihood Model estimates wildfire-season ignition probability for overhead electric distribution asset locations and provides the likelihood input to WDRM Wildfire Risk calculations that are aggregated to the Circuit Segment level. WDRM Wildfire Risk estimates are used routinely for informing work plan prioritization to monitor and mitigate risk. An overview of the DEPM suite of models is provided in Sections 1 and 3.1 of the DEPM documentation.

b. Model Type

The Ignition Likelihood model is comprised of a suite of supporting failure/outage event-probability models and a Probability of Ignition Given Outage model. The supporting failure/outage models are Machine Learning models that use either XGBoost or Maximum Entropy, while the Probability of Ignition Given Outage model uses logistic regression. Section 3 of the DEPM documentation describes

each model's taxonomy in the corresponding "Algorithm Selection" subsection.

c. Key Inputs

Each of the asset, contact-from-object, and ignition event probability models use many input datasets providing information about the equipment type, equipment attributes, and the surrounding weather and environmental conditions. Section 3 of the DEPM documentation describes each of the asset, contact-from-object, and ignition event probability model's input data (see "Covariate Selection").

d. Model Solution

Each event-probability model is developed using historical failure, outage, and ignition data from the peak wildfire season months of June through November 2015-2022. Model performance is evaluated using an out-of-sample test dataset. Section 3.2.1 of the DEPM documentation describes the performance metrics used to evaluate the models, including Receiver Operating Characteristic Area Under the Curve (ROC AUC), precision-recall, and 20 percent concentration factor. Section 3 then describes each of the 24 asset, contact-from-object, and ignition event probability models. For each model, the "Model Data," "Key Developments," "Performance," "Algorithm Selection," and "Covariate Selection" sections describe the development and solution.

e. Model Outputs

The Ignition Likelihood model outputs wildfire-season probabilities of ignition. For equipment asset models, outputs are produced at the individual asset level; for contact-from-object models, outputs are produced at the 100m x 100m-pixel level. The 23 probability-of-outage model outputs are used as inputs to the Probability of Ignition Given Outage model to estimate ignition likelihood. Ignition probabilities are combined with wildfire consequence values to calculate Wildfire Risk for the WDRM and aggregate to Circuit Segments. Section 3.6 of the DEPM documentation describes how the failure/outage model outputs are used to produce overall Ignition Likelihood.

f. Uncertainty

Due to ignitions and failures occurring infrequently, there is limited direct evidence about the true risk of any single asset or location. This makes it difficult to calculate a precise uncertainty range for each individual model prediction. Accordingly, uncertainty for the Ignition Likelihood model is characterized primarily through individual event-probability model performance metrics, feature diagnostics, and documented model limitations, rather than through formal uncertainty bounds for each output.

For the asset-based models, missing input data was less limiting because XGBoost was selected in part for its ability to handle missing values. For other models, records with insufficient attribute or covariate data were excluded from model development and prediction. In practice, this was uncommon because records missing key attributes were generally screened out during data preparation.

PG&E has taken a bootstrapping approach to produce a 95 percent confidence interval for the median Circuit Segment Ignition Likelihood per primary overhead High Fire Threat District (HFTD) or High Fire Risk Area (HFRA) mile. The results of this analysis are included in EUP Risk Model Backtesting Table (Table C.5), discussed in Chapter 6, Section C.1.b.5.

For Ignition Likelihood, PG&E evaluates uncertainty more broadly by comparing out-of-sample model performance and using feature diagnostics, such as feature importance plots and SHAP plots, to understand which inputs most strongly influence model results. These diagnostics also help assess model sensitivity by showing how changes in input variables are associated with changes in predicted outcomes. Model performance metrics and feature diagnostics are described in DEPM Section 3.2.1, while model-specific performance results are provided in the “Performance” subsections of DEPM Section 3.5 for the failure/outage models and DEPM Section 3.6.1.2 for the Probability of Ignition Given Outage model. Model-specific feature importance and SHAP results are provided in the “Covariate Selection” subsections.

g. Toy Problems

To illustrate how the Ignition Likelihood model combines the likelihood of a failure or outage with the conditional likelihood of ignition given that failure/outage, three conceptual synthetic toy problems are presented in the Ignition Likelihood Workpaper (Attach. B, WP029) using the equipment-caused primary conductor wire down failure sub-model. These examples are illustrative only. The machine-learning models are non-linear and are designed for inference rather than causality; the relationships described below rely on feature-importance metrics to demonstrate model behavior under low-, medium-, and high-risk conditions.

The low-risk case represents benign operating conditions with less dry fuels and fewer conductors. Both the primary conductor failure likelihood and the probability of ignition given failure are lower than those in the high-risk case, resulting in a lower overall wildfire season ignition likelihood.

The medium-risk case reflects elevated conditions driven by dry fuels and many conductors but is moderated by the non-burnable land surface. The primary conductor failure likelihood is moderately elevated due to increased exposure of conductors, while the probability of ignition given failure is elevated due to dry fuels. Together, these inputs produce a mid-range wildfire-season ignition likelihood.

The high-risk case reflects elevated conductor failure conditions characterized by a low soil erodibility factor and unfavorable relative humidity. In this scenario, the probability of ignition given failure is driven by moderately dry fuels and moderate wind speed with majority shrub groundcover, producing an elevated wildfire-season ignition likelihood. The combination of elevated failure likelihood and elevated ignition given failure likelihood results in a high likelihood of ignition.

h. Shelf-Life

WDRM v4 is expected to be used until the next update. Model updates are generally performed to support major deliverables, such as the WMPs and GRCs. WDRM v4 supported the 2026–2028 WMP and 2027–2031 GRC.

PG&E intends to release an update to the WDRM in 2028 to support the 2031–2034 WMP and GRC. The update is expected to include a model refresh using new calibration data, refreshed input datasets, and enhancements to model structure and methodology.

2. Model Report Chapter 2– Ignition Consequence Model

a. Model Usage

The model estimates the expected outcome of a wildfire initiated at the location of overhead distribution lines and provides the consequence component of WDRM v4 Wildfire Risk calculations aggregated to the Circuit Segment level to inform work plan prioritization to monitor and mitigate risk. The model evaluates the consequence portion of the electrical system's Wildfire Risk profile by estimating the severity of potential wildfire outcomes—including acres burned, buildings destroyed, and fatalities—by converting those outcomes into a single consequence value through a Multi-Attribute Value function (MAVf). (See also Wildfire Consequence Model WP, Attach. B, WP025.)

b. Model Type

The model combines a Base Consequence Model with two adjustment models for wildfire suppression and public egress. The Base Model assigns historical daily fire conditions to eight partitions and estimates an average MAVf-based consequence score for each partition. Suppression and Egress are fit as Binomial generalized linear models with a logit link that adjust those scores to produce the final location-specific consequence value used in WDRM v4 risk calculations. (See also Attach. B, WP025 Sections 3 and 4.)

c. Key Inputs

The model uses historical wildfire outcomes and location-based indicators to estimate ignition impacts at each modeled location. Key inputs are NASA VIIRS detections, CAL FIRE Red Books, and CPUC Safety and Enforcement Division (SED) reports for acres burned, structures destroyed, and fatalities. Base scores are determined from HFRA status,[182] Dry Wind Conditions, and Predicted Destructive conditions, with the latter informed by 24-hour wildfire simulations and Fire Potential Index (FPI) outputs used for PSPS decision-making. Adjusted consequence uses Technosylva's Terrain Difficulty Index (TDI) for suppression difficulty and PG&E's AFN index to model egress challenges (see Sections 3.2 and 3.3 of Attach. B, WP0025 and Attach. B, WP028 (Ignition Consequence Toy Problem).

d. Model Solution

The model is implemented in two stages: a base consequence sub-model and an adjustment for public egress and wildfire suppression. The sub-model uses 2012–2022 records to assign each historical fire one of eight condition partitions based on three true/false criteria—HFRA status, Dry-Wind Conditions, and Predicted-Destructive conditions; and a consequence score calculated using the MAVf to convert acres burned, structures destroyed, and fatalities into a single value. The model then derives an average MAVf consequence score for each of the eight partitions.

The adjusted consequence calculation applies wildfire suppression and public egress models to refine the base consequence values. The suppression model was fit using historical fire data with the dependent variable represented as the portion of buildings survived. The egress model was fit using the same historical fire data with fractional fatalities as the dependent variable, meaning the model estimates the expected fatality rate associated with the number of structures destroyed rather than a fatality count. The model-fit diagnostics for the regression

[182] High Fire Risk Area (HFRA) refers to utility-identified areas considered at high risk for wildfire. When used in "HFRA status," the term HFRA includes both HFRA and HFTD.

models can be expressed in terms of deviance ratios relative to a null, or non-existent, model. The full model deviance ratios for suppression is 0.755 versus 1.000 for the null model and for egress it is 0.898 versus 1.000 for the null model.

After the suppression and egress adjustments are estimated, the model constructs adjusted consequence tables that are referenced during application to grid asset locations. For each location, the model calculates daily consequence values across 11 wildfire seasons from 2012 through 2022 and then averages those daily values to produce the final location-specific consequence score used in WDRM. The final day-weighted average consequence scores in the WDRM were evaluated on a performance curve displaying the model's ability to capture the worst historical fire outcomes (acres burned, structures destroyed, and fatalities) within the highest rank ordered pixel locations. (See also Attach. B, WP026 (Wildfire Consequence v4 Performance Figure 16).)

e. Model Outputs

The model produces a location-specific consequence score representing the expected consequence of an ignition at each modeled location. The model calculates daily consequence values for each 100m-by-100m grid pixel across 11 wildfire seasons (2012-2022) and then averages those values to produce the final consequence score. The score is used as the consequence component in WDRM, where risk is calculated by combining ignition probability and wildfire consequence. (See also Consequence Model WP, Attach. B, WP025, Sections 3.5 and 4.3.2.)

f. Uncertainty

The WFC v4 model produces fire season daily averaged consequence outcomes for historical ignitions in 100m x 100m pixels. It is unlikely that an ignition event will result in the predicted seasonal average consequence for that location due to variations in daily conditions, which make rigorous uncertainty evaluations difficult. The only known ignition outcomes are those for historical wildfires with

different causes of fire and local conditions at the time of ignition. PG&E used historical wildfire outcomes to calibrate the consequence model decision table used to predict a base consequence value for any given pixel for the daily conditions during a fire season.

PG&E has taken a bootstrapping approach to produce a 95 percent confidence interval for the median Circuit Segment Ignition Consequence per primary overhead HFTD or HFRA mile. (See Progress Report 0, Risk Model Backtesting Table C.5.)

For the Ignition Consequence sub-models, records with insufficient attribute or covariate data were excluded from model development and prediction. In practice, this has occurred infrequently because key inputs, such as weather variables, have broad spatial and temporal coverage through reanalysis and because other inputs, including the fire simulations, TDI, and AFN, are derived for all grid locations.

g. Toy Problems

The three Ignition Consequence Toy Problems correspond directly to the Base Consequence Model condition partitions—HFRA status, Dry Wind Conditions, and Predicted Destructive conditions—and to the suppression and egress adjustment models that modify base consequence outcomes. (See also Ignition Consequence Toy Problem, Attach. B, WP028.)

The Low-Risk example corresponds to locations outside HFTD/HFRA that do not meet the threshold criteria for Dry Wind Conditions or Predicted Destructive Conditions and have favorable access and terrain characteristics. Wildfire suppression is generally effective (low TDI) and public evacuation is less constrained (low AFN), resulting in a low consequence score. Such conditions are most common during typical operating periods outside of HFTD/HFRA.

The Medium-Risk example corresponds to HFTD/HFRA locations that do not meet the criteria for Dry Wind Conditions or Predicted Destructive Conditions and have moderate access and terrain characteristics. These conditions are associated with moderate fire spread potential and partial reductions in suppression effectiveness. These moderate TDI values increase the likelihood of structures

destroyed while moderate AFN values may modestly increase evacuation challenges and expected fatalities. Together these factors produce a mid-range consequence score and occur frequently during wildfire season in HFTD/HFRA under elevated but not extreme conditions.

The High-Risk example corresponds to HFTD/HFRA locations that meet the criteria for both Dry Wind Conditions and Predicted Destructive conditions, representing the most severe Base Consequence partition. These conditions are combined with high TDI, indicating challenging terrain and reduced suppression effectiveness, and high AFN, reflecting greater evacuation challenges and higher expected fatalities. Together, these factors result in the highest consequence scores and occur infrequently during wildfire season.

h. Shelf-Life

Chapter 7, Section D.1.h (Ignition Likelihood Model Shelf-Life) details the shelf-life methodology applicable to this model.

3. Model Report Chapter 3A – OPRM: EPSS

a. Model Usage

The OPRM quantifies in dollars the risk resulting from EPSS and PSPS caused outages. This chapter describes the EPSS risk model. The EPSS Risk Model and the PSPS Risk Model produce risk and likelihood values that feed into the OPRM. The EPSS Risk Model quantifies (in dollars) the expected impact of sustained outages on a Circuit Segment when EPSS is enabled. It also evaluates the incremental reliability risk introduced by enabling EPSS (see also Outage Program Risk Model Documentation, Attach. B, WP019).

b. Model Type

The EPSS Risk Model is a deterministic mathematical model. It uses a rule-based formulation to compute the expected number and duration of sustained outages that include: (1) Historical outage rates; (2) EPSS enablement schedules; (3) Empirical sustained outage fractions; (4) Outage duration; (5) Number of affected customers; and (6) Economic VoS interruption.

c. Key Inputs

EPSS likelihood considers the probability of an outage that is based on the probability of failure from WDRM sub-models. It also considers the expected duration of that outage derived from the Distribution Reliability Value Model when EPSS is enabled. Inputs are derived from internal models (WDRM v4 and IGP) and historical outage data, filtered for HFTD/HFRA areas. (See also EPSS Risk Model Documentation, Attach. B, WP018.)

Key inputs include:

- **N_outages,s,cs**: Expected number of outages by WDRM subset and Circuit Segment
- **D_outages,s,cs**: Expected duration of an outage on a Circuit Segment, which is derived by a weighted average for each modeled asset type (conductor and support structures) and the protective devices they are downstream from (breaker, dynamic protective device, fuse, switch), on a Circuit Segment mapped to WDRM v4 subsets
- **f_EPSS_enabled**: Fraction of wildfire season during which EPSS is enabled, based on EPSS lookback and historical enablement data
- **f_sustained,s**: Fraction of outages that are sustained (vs. momentary) for each subset when EPSS is disabled. When EPSS is enabled, it assumes that all outages are sustained outages.

The consequence component of the model quantifies the impact of a sustained outage on a Circuit Segment when EPSS is enabled. It is used to estimate customer impacts in terms of the VoS lost for the number and types of customers impacted. Key inputs for the consequence calculation include:

- **VoS**: VoS from the Interruption Cost Estimate calculator, version 2.0 (dollars per minute); and
- **Incremental customer count**: The count of customers downstream of each EPSS-enabled protective device compared to the count of customers impacted by a non-EPSS outage. There are typically more downstream customers of an EPSS device than those downstream of a traditional protective device, because EPSS

devices are generally installed on upstream portions of the circuit and de-energize a larger section. As a result, customers impacted by a non-EPSS outage would generally represent a subset of the customers impacted by an EPSS outage.

d. Model Solution

The EPSS Risk Model estimates the reliability risk introduced by enabling EPSS during wildfire season. It is applied at the Circuit Segment level and is designed to estimate the expected impact of sustained outages in monetary terms. The model evaluates the expected number and consequence of sustained outages on a Circuit Segment when EPSS is enabled, which is then compared to a counterfactual scenario where EPSS is disabled. This approach isolates the reliability impact associated with EPSS enablement.

To quantify the incremental reliability risk introduced by EPSS, the model compares two scenarios: when EPSS is enabled and when it is not. We evaluate these scenarios over the same period for consistency. This allows PG&E to isolate the additional Outage Program Risk attributable solely to EPSS and exclude other seasonal or operational factors. A full derivation of the model's solution is in the EPSS Outage Risk Model Documentation (see EPSS Outage Program Risk Model Documentation, Attach. B, WP019).

e. Model Outputs

The EPSS Risk Model output is a scalar value representing the expected impact of sustained outages per Circuit Segment during the EPSS-enabled portion of wildfire season. The following data outputs are captured in the EPSS Risk Model: (1) Annual dollarized risk per Circuit Segment; (2) Incremental increase in annual Customer Minutes Interrupted (CMI) per Circuit Segment from EPSS; (3) Annual likelihood per Circuit Segment in outage minutes per year; and (4) Consequence per Circuit Segment in dollars per outage minute. This output feeds into the overall OPRM in combination with data from the PSPS Risk Model.

f. Uncertainty

PG&E has taken a bootstrapping approach to produce a 95 percent confidence interval for the median Circuit Segment total outage program risk per primary OH HFTD or HFRA mile. The total outage program risk is the sum of PSPS and EPSS outage program risks. The results of this analysis are included in EUP Risk Model Backtesting Table (Table C.5), discussed in Chapter 6, section C.1.b.5.

g. Toy Problems

PG&E provided the data for three example toy problems (low, medium, high risk) in the EPSS OPRM. Attach. B, WP016 details the calculation methodology for the EPSS OPRM. The low-risk case represents a Circuit Segment with minimal incremental exposure from EPSS enablement. The segment has a low EPSS enablement rate and/or low underlying failure probability, resulting in a low number of momentary outages converted to sustained outages per wildfire season. The segment also serves a small number of customers downstream of EPSS protective devices, producing a low level of incremental CMI. The combined low likelihood and low impact result in a low overall risk, which represents the majority of EPSS enabled Circuit Segments in our service territory.

The medium-risk case reflects a Circuit Segment with moderate incremental outage exposure from EPSS enablement. The segment experiences a moderate number of conversions per wildfire season, driven by moderate failure probability and EPSS enablement history. Each segment serves a moderate customer base, producing a mid-range level of incremental CMI per converted event. Together, these inputs yield a medium overall risk. Conditions of this type occur on a meaningful subset of segments in areas with higher EPSS utilization.

The high-risk case reflects a Circuit Segment with significant incremental outage frequency from EPSS enablement. The segment serves a large customer base downstream of EPSS protective devices, with each event producing substantial incremental CMI due to the wider EPSS isolation footprint and outage duration. The combination of high

likelihood and high impact yields a high overall risk. Such conditions occur on a small number of segments concentrated in PG&E's most EPSS-active circuits with dense customer populations.

TABLE 7-3:
EPSS TOY PROBLEM – KEY METRICS BY RISK CATEGORY

Line No.	Risk	EPSS Enablement Rate	EPSS Annual CMI (minutes)	EPSS expected outages/yr	EPSS CMI per outage (minutes)	Risk $/yr
1	Low Risk	0.1085	19,098	0.0188	1,016,494	$23,245
2	Medium Risk	0.4879	1,439,386	0.9407	1,539,102	3,781,857
3	High Risk	0.9578	4,206,096	1.1178	3,762,951	$16,082,076

h. Shelf-life

Similar to the WDRM shelf life as described in Section D.1.h above, this model is intended to be updated every four years with new calibration and input data beginning in 2028 for the 2031-2034 WMP and GRC.

4. Model Report Chapter 3B – OPRM: PSPS

a. Model Usage

The PSPS Risk Model calculates dollarized risk and outage predictions (minutes of interruption) at the Circuit Segment level. Risk is based on the historical likelihood of a segment being present within a PSPS polygon over the seven-year lookback period of the input data (2018-2024). Customer outage costs originate at each segment and are then redistributed to upstream segments using mileage-weighted coefficients. This reflects that de-energizing an upstream segment causes outages on all downstream segments. Segments with more exposed mileage within a PSPS event polygon receive proportionally more redistributed risk. In effect, this model calculates the risk that could be averted by undergrounding a given Circuit Segment.[183]

[183] Attach. B, WP019 provides further details on the Outage Program Risk Model.

b. Model Type

The PSPS Risk Model is a deterministic mathematical model. It uses a rule-based formulation to compute the expected number of sustained outages that include: (1) circuit geometry; (2) aggregated customer value-of-service data; and (3) historical PSPS event polygons. The PSPS Risk Model does not involve simulation, machine learning, or statistical inference.

c. Key Inputs

Key inputs to the PSPS Risk Model include:

- **The PSPS Lookback Study**: This dataset provides seven years of PSPS event data including event polygons, outage duration in minutes, and affected Circuit Segments and Service Point IDs starting in 2018.
- **The WDRM v4**: The WDRM is the PSPS Risk Model's source of record for Circuit Segment geometry.
- **PG&E Customer Segmentation Data**: This data identifies the customer service classes and critical customer factors for SPIDs affected by PSPS events.

These inputs are derived from historic PSPS lookback event data over the last seven years and WDRM data about the geometry of affected circuits. The PSPS lookback includes all potential weather events and the number of customers impacted and the duration. The lookback also identifies the event type. For the PSPS model Distribution only and Distribution/Transmission are the only events considered.

d. Model Solution

The PSPS Risk Model used in the OPRM is a circuit-based/ source-based mileage-weighted risk model. It is derived from the risk associated with customer loss of service on a Circuit Segment. To account for the downstream impact of de-energization triggered by PSPS conditions upstream on a circuit, the customer experienced risk on downstream Circuit Segments is distributed upstream to Circuit Segments within PSPS weather event polygons based on the Circuit

Segment's exposure to PSPS conditions, i.e., the length of the Circuit Segment within the polygon.

The outage risk of each downstream Circuit Segment is modeled as a risk rate per mile: R_i/M_A, where R_i is the customer-experienced risk on a given downstream Circuit Segment i and M_A is the total exposed mileage of its ancestor (upstream) segments within the PSPS event polygon. The risk rate is then attributed to each upstream Circuit Segment in proportion to its exposed mileage: $R_{cs} = M_{cs} *(R_i/M_A)$, where M_{cs} is the length of segment cs within the event polygon. The total risk on a given Circuit Segment is therefore the sum of all downstream mileage-weighted risk attributed to it.

A full derivation of the model's solution and example calculations are in the PSPS Risk Model Documentation, Attach. B, WP020.

e. Model Outputs

The PSPS Risk Model output is a scalar-value dataset representing the expected risk of sustained outages per Circuit Segment during a year of PSPS events. The following data outputs are captured: (1) Annual dollarized risk per Circuit Segment; (2) Annual likelihood per Circuit Segment in outage minutes per year; (3) Annual CMI per Circuit Segment; and (4) Consequence per Circuit Segment in dollars per outage minute. This output feeds into the overall OPRM in combination with data from the EPSS model.

f. Uncertainty

PG&E has taken a bootstrapping approach to produce a 95 percent confidence interval for the median circuit segment total outage program risk per primary overhead HFTD or HFRA mile. The total outage program risk is the sum of PSPS and EPSS outage program risks. The results of this analysis are included in EUP Risk Model Backtesting Table (Table C.5).

Because there is no machine learning component to this deterministic model, uncertainty arises primarily from the use of variable historical PSPS events as a proxy for the likely location and frequency of

future PSPS events. This uncertainty is mitigated by using seven years of PSPS event history.

g. Toy Problems

To illustrate how the PSPS model categorizes Circuit Segment risk, PG&E provided the data for three example toy problems (low, medium, high risk) in the PSPS OPRM. PG&E has attached the calculation methodology for the PSPS OPRM.[184] By looking at the historical likelihood of a circuit segment being de-energized and the typical severity of those de-energizations in terms of total customer-minutes of interruption, we can produce a combined risk category.

The low-risk case represents a Circuit Segment with minimal exposure to PSPS event polygons over the seven-year lookback period. The segment serves a small number of customers and is rarely included in PSPS scoping, with limited customer-minutes of interruption in the rare case an event does occur. The combined low likelihood and low impact result in a low overall risk category, which represents most Circuit Segments across PG&E's system.

The medium-risk case reflects a Circuit Segment with moderate exposure to PSPS event polygons. The segment experiences a moderate frequency of PSPS events and serves a medium-size customer base, producing a mid-range level of customer-minutes of interruption per event. Together, these inputs yield a medium overall risk category. Conditions of this type occur on a meaningful subset of segments in HFTD/HFRA areas.

The high-risk case reflects a Circuit Segment within high-wind corridors and fire-prone areas, with significant historical PSPS exposure and a large or critical-customer-heavy customer base. The segment is frequently included in PSPS scoping, with each event producing substantial customer-minutes of interruption due to the customer count and outage duration. The combination of high likelihood and high impact yields a high overall risk category. Such conditions occur on a

184 See Attach. B, WP017 for more details on the PSPS Toy Problem.

relatively small number of Circuit Segments concentrated in PG&E's highest-risk geographic areas.

TABLE 7-4:
PSPS TOY PROBLEM – KEY METRICS BY RISK CATEGORY

Line No.	Risk Category	PSPS Outages/year	PSPS CMI per Outage (minutes)	Risk Dollarized/year
1	Low Risk	0.2857	251,970	$72,345
2	Medium Risk	1.0000	674,361	$2,823,353
3	High Risk	1.5714	1,555,238	$6,505,539

h. Shelf-Life

Chapter 7, Section D.3.h (OPRM: EPSS Shelf Life) details the shelf-life methodology applicable to this model.

5. Model Report Chapter 4 – Overall Utility Risk Model

a. Model Usage

PG&E calculates Overall Utility Risk (OUR), a required KDMM, by combining Ignition Risk and Outage Program Risk at the Circuit-Segment level. The Overall Utility Risk calculation is presented in this Model Report consistent with the EUP Guidelines' requirement for an Overall Utility Risk model. OUR is used as the top-level combined risk metric at the project level, Portfolio level, and system level, enabling project-level comparisons, Portfolio aggregation, system-level risk assessment, and KDMM reporting. It provides a single, monetized composite metric, allowing for standardized comparison across projects, Portfolios, and the electric distribution system.

b. Model Type

The Overall Utility Risk calculation is a deterministic, rule-based aggregation of Ignition Risk and Outage Program Risk (EPSS and PSPS risks). Rather than serving as a primary risk estimation model, it integrates outputs from the WDRM and OPRM, applying defined climate adjustment factors and escalation parameters to produce a consolidated view of utility risks. As a deterministic algebraic framework, calculations are not independently calibrated and instead inherit underlying

assumptions, methodologies, and input dependencies from the upstream risk models, ensuring consistency with the foundational risk frameworks.

c. Key Inputs

The Key inputs to Overall Utility Risk include:

- **Ignition Risk**: monetized Circuit Segment Wildfire Risk
- **Outage Program Risk**: monetized Circuit Segment outage risk associated with Outage Programs.
- **Climate change factors**: Project-level multipliers applied over time to reflect changing future conditions
- **Escalation factors**: multipliers used to express future values in comparable nominal terms.

Escalation and climate change factors are described in Section G.4 below (Core Capability 4), Core Capability 4 Workpaper (Attach. B, WP011) and WBCA Whitepaper (Attach. B, WP006).

d. Model Solution

Overall Utility Risk is the sum of Ignition and Reliability Risk and incorporates climate change and escalation.

e. Model Outputs

The calculation produces an Overall Utility Risk for each distribution Circuit Segment in PG&E's service territory.

f. Uncertainty

PG&E has taken a bootstrapping approach to produce a 95 percent confidence interval for the median Circuit Segment Overall Utility Risk per primary overhead HFTD or HFRA mile. The results of this analysis are included in EUP Risk Model Backtesting Table (Progress Report Table C.5), discussed in Chapter 6, Section C.1.b.5.

g. Toy Problems

The Overall Utility Risk Toy Problem (Attach. B, WP031) provides the toy-model inputs, outputs, and calculations.

h. Shelf-Life

The Overall Utility Risk Calculation Shelf-life is directly dependent on the shelf-life of the contributing models for Ignition Risk and Outage Program Risk. (See Section D.1.h. and D.3.h for the applicable model Shelf-life for all relevant input models.)

6. Model Report Chapter 5 – WCBA Model

a. Model Usage

The WBCA evaluates and compares different system hardening mitigations at the Circuit Segment level by estimating the costs and benefits of implementing a particular mitigation at a specific location, and the resulting reduction in safety, ignition and outage risk. Unlike PG&E's ignition and OPRMs, the WBCA ingests information from the ignition and OPRMs, along with public safety risk, baseline reliability risk, mitigation effectiveness, cost, and financial information, and performs calculations that inform PG&E's mitigation selection.

b. Model Type

The WBCA is built in the Foundry platform. PG&E aggregates Ignition Risk data from the WDRM v4, outage program and baseline outage risk data from the OPRM, public safety risk data, lifetime costs and benefits, and mitigation effectiveness information to calculate Circuit-Segment level BCRs. (See Attach. B, WP006.)

c. Key Inputs

The key inputs into the WBCA are:

- **Ignition Risk Data:** Ignition Risk data from WDRM v4.
- **Outage Program Risk Data:** Outage Risk data from OPRM.
- **Baseline Outage Risk Data:** From a branch of PG&E's OPRM that accounts for the *non-EPSS* outage risk using WDRM probabilities of failure.
- **Public Safety Risk Data:** Also referred to as Public Contact with Energized Electric Equipment (PCEEE), this input estimates the likelihood and consequences of public contact with intact energized equipment and prioritizes safety-driven investments using both

quantitative results and qualitative regulatory and operational considerations. (See PCEEE Risk WP, Attach. B, WP022)

- **Cost Data:** Includes the estimated present value capital costs for the capital project costs plus the estimated present value lifetime O&M costs. Estimated capital costs are based on historic values for similar activities adjusted for inflation and other factors. The O&M costs information is derived from the imputed adopted costs in PG&E's 2023 GRC. (See WBCA WP, Attach. B, WP006.)
- **Benefits Data:** Includes the wildfire benefit (the wildfire risk reduction associated with each Circuit Segment for a particular mitigation); public safety benefit (the non-wildfire risk a Circuit Segment poses to the public); baseline reliability benefit (the monetary value of avoided CMI due to implementing a particular wildfire mitigation); EPSS benefit (the reduction in EPSS exposure associated with each Circuit Segment when a particular mitigation is implemented); and PSPS benefit (the reduction in PSPS exposure associated with each Circuit Segment when a particular mitigation is implemented).
- **Mitigation Effectiveness:** Estimated blended average effectiveness expressed as a percentage for each Alternative Mitigation. PG&E calculates effectiveness by assessing how well individual mitigations and mitigation combinations reduce ignition risk from unplanned outage events and equipment attributes ("outage combinations"). PG&E assessed the effectiveness of more than 2,700 outage combinations that have occurred in PG&E's HFTD areas during wildfire season. PG&E Subject Matter Experts (SME) reviewed each combination, defined by a basic event and three attributes (supplemental ignition cause, involved equipment, and equipment condition), and assigned effectiveness ratings reflecting each mitigation's ability to prevent that combination.
- **Climate Impacts:** Wildfire and reliability risk benefits consider anticipated climate change impacts from 2028-2082 using two key factors: (1) Fire Weather Index (FWI) Analysis; and (2) Heat Day Analysis. (See also WBCA Section G.4 (Core Capability 4).)

- **Financing Data:** Includes financing elements used to calculate annual cash flows and compare costs and benefits by Alternative Mitigation including Present Value of Revenue Requirement, nominal and real discount rates and inflation rates. (See also Ch. 5, Section C.3 a. and WBCA WP, Attach. B, WP006.)

d. Model Solution

The WBCA Model is not a predictive or optimization-based model that is calibrated or trained; rather, it ingests wildfire ignition risk, public safety risk, and reliability risk estimates from upstream risk models (WDRM, OPRM), with standardized cost, financial, and effectiveness assumptions. It evaluates the present value (PV) of lifetime benefits and costs of each mitigation considered, applying consistent discounting, asset life assumptions, and climate adjustment multipliers.

As the WBCA is an algebraic aggregation of fixed inputs rather than a fitted model, there is no parameter estimation, validation accuracy, or convergence criterion associated with its solution. It does not solve a non-convex optimization problem, train an over-parameterized network, or evolve a physical simulation over space and time.

e. Model Output

The WBCA outputs Circuit Segment BCR values for each comparison: (1) 100 percent Underground; (2) 100 percent Overhead Hardening; (3) 100 percent Remote Grid; and (4) Hybrid – 50 percent Underground/50 percent Overhead Hardening.

PG&E uses WBCA outputs to inform mitigation selection for each Eligible Circuit Segment. If the WBCA output indicates that a hybrid solution is the preferred mitigation, PG&E further analyzes the hybrid solution through the Feedback Loop in Screen 3. (See Ch. 3, Section D.3. for details of the Feedback Loop and Screen 3 process.)

f. Uncertainty

To account for uncertainty throughout the various factors in the WBCA, PG&E, consistent with the IOUs' proposal in Application (A.) 26-02-005, includes an estimate uncertainty range when using the WBCA outputs for mitigation decision-making. The BCR estimate

uncertainty range provides a transparent mechanism to account for known model limitations and to incorporate site-specific risk factors not fully represented in quantitative outputs, described in Chapter 3, Section D.3.a.6.

The BCR estimate uncertainty range is estimated to be 30 percent, consistent with Energy Safety's decision on our 2026-2028 WMP.[185] To operationalize this uncertainty range for Project selection, we apply a comparison framework when evaluating Mitigation Alternatives with close BCRs. Specifically, when the BCR for undergrounding is at least 70 percent of the BCR of an alternative, undergrounding is considered comparable. This 70-percent comparison standard reflects the 30-percent uncertainty range and does not represent a separate eligibility threshold or a modification to the BCR methodology.

g. Toy Problems

The Toy Problem with varying inputs and associated outputs of the WBCA are included in Workpaper WBCA Toy Problem (Attach. B, WP024). The values in the Toy Problem are representative of real-world data as the costs and benefits of individual Projects will vary.

h. Shelf-Life

PG&E expects to use this model for the life of the EUP. We expect to update the model with updated inputs aligned with each WDRM risk model version update, consistent with Section D.1.h below. PG&E plans to update WBCA cost assumptions generally annually to align with the prior year's actual costs. These assumptions will be discounted back to 2028 dollars so that projects can be compared equally throughout the EUP. As the WBCA model relies on the WDRM, OPRM and Enterprise Bow Tie data and models, PG&E will update the WBCA model version every four years beginning in 2028 to align with the anticipated timing of the 2031-2034 WMP and GRC.

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185 Energy Safety's Decision for the PG&E 2026-2028 Base Wildfire Mitigation Plan (Feb. 5, 2026), p. 19.

7. Model Report Chapter 6 – Enterprise Risk Bow Tie

a. Model Usage

PG&E's Enterprise Risk Bow Tie model quantifies enterprise risks using a company-wide risk assessment methodology in compliance with the CPUC's RDF. The Bow Tie models support quantitative assessments of risks and mitigations for major proceedings including RAMP and GRC and internal planning and decision-making.[186]

For the EUP, PG&E primarily uses the Wildfire Risk Bow Tie model (WLDFR) to quantify the annual expected Wildfire Risk associated with PG&E's electric infrastructure in risk-adjusted dollars. This annual Wildfire Risk value is used to evaluate the potential risk reduction from system hardening programs. PG&E also uses safety risk values from other Enterprise Bow Tie models (e.g., PSPS, EPSS, PCEEE) to capture additional safety consequences in the Overall Utility Risk reduction. This approach aligns with the RDF by providing a consistent, monetized metric for comparing and prioritizing risk mitigation strategies.

b. Model Type

The Bow Tie models can be considered mathematical, probabilistic models. In a Bow Tie model, a Risk Event is represented with a list of drivers that potentially lead to the Risk Event occurring with estimated likelihood and a list of outcomes describing consequence severity if the Risk Event occurs. Outcomes are characterized by probability distributions of the potential levels of impact from a risk event across consequence attributes such as direct safety, indirect safety, electric reliability, and financial attributes, then aggregated into a single CoRE value after applying the CPUC Cost-Benefit Approach. Annual risk is calculated as the sum, over all outcomes, of the product of each outcome's expected annual frequency and its corresponding CoRE.

c. Key Inputs

Below are the key inputs for the Wildfire Risk Bow Tie Model:

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[186] Further detail of the Enterprise Bow Tie Model is outlined in A. 24-05-008, PG&E's 2024 RAMP Report, Exhibit (PG&E-4), Chapter 1 available here: 2024-ramp-application-pge051524.pdf. See also PG&E's GRC, A.25-05-015, Exhibit (PG&E-4), Ch. 3.

- **PG&E facility ignition data:** Internal ignition investigation records used to estimate wildfire ignition frequency and consequence.
- **PSPS damages and hazards data:** Field observations of damaged equipment and hazard conditions identified during post-PSPS event patrols, enabling estimation of prevented potential ignition incidents.
- **CAL FIRE large fire records:** Public data on wildfires exceeding 300 acres within PG&E's service territory, including fire location, acres burned, fatalities, and structures destroyed. This data supports consequence distribution fitting and allocation of frequency into large and destructive fire outcomes.
- **EPSS outage data:** Actual sustained outage events on EPSS-enabled circuits, recorded in PG&E's Integrated Logging and Information System (ILIS) outage database. This data provides the count and details of outages (location, cause, CMI, etc.), used to estimate the number of ignitions avoided due to EPSS enablement.
- **Value of Statistical Life (VSL):** Standardized dollar valuation of human life/safety per U.S. Department of Transportation guidance, used to monetize fatalities and serious injuries.
- **Value of Service (VoS):** Dollar-per-minute cost of interrupted service per customer (expressed as $ per customer minutes interrupted), from the LBNL ICE Calculator v1.0 (the version in effect when the 2024 RAMP was prepared), used to monetize the electric reliability impact (customers minutes interrupted).

d. Model Solution

The Bow Tie models calculate annual risk as the sum, across all outcomes, of expected annual frequency multiplied by the CoRE. For the Wildfire Risk Bow Tie model, frequencies are estimated as the sum of annualized historical PG&E ignition counts, avoided ignitions from PSPS and EPSS. PSPS avoided ignitions are estimated by multiplying historical PSPS damages and hazards counts by the outage-to-ignition rates during similar historical conditions, and EPSS avoided ignitions are estimated based on historical EPSS outage counts multiplied by outage-to-ignition rate estimated during similar historical conditions. Total frequency is then broken down by outcomes, by applying the

conditional probability of ignition resulting in each outcome, estimated by PG&E ignition data and CAL FIRE large fire records.

The outcomes are characterized using probability distributions over the applicable consequence attributes (safety, indirect safety, electric reliability, and financial) based on PG&E ignition and outage data and CAL FIRE large fire data. The CoRE for each outcome is computed as sum of the expected value of each of the Attribute Values' probability distribution monetized using the monetization factors (VoS and VSL) and Risk Attitude function following the CPUC's Cost-Benefit Approach.

e. Model Output

The Wildfire Risk Bow Tie model provides several key outputs for the Baseline per year. These include: (1) the Event Frequency, the expected number of wildfire ignition events per year; (2) the Expected Consequences by Attribute, which are provided in natural units, monetized levels and risk-adjusted levels; and (3) the Risk Value, which is annual expected Wildfire Risk in risk-adjusted dollars, calculated by multiplying frequency and CoRE.

The monetized annual risk values from the Bow Tie model feed into the WBCA which uses the data to translate risk reductions for each Alternative Mitigation and Additional Comparison into equivalent monetized benefits. The WBCA model aggregates these annual risk-adjusted benefit values and applies time-discounting. The WBCA calculates BCRs that reflect risk reduction benefits in dollar terms relative to mitigation costs using the Bow Tie model outputs to evaluate Projects on a consistent basis.

f. Uncertainty

The 2015-2024 data used to estimate ignition frequency and consequence represents a single realization of a non-stationary process and may not fully represent the current climate average conditions. This contributes to statistical uncertainty in the estimated model parameters. Applying the lower and upper bounds of the 50 percent Confidence Intervals (CI) for key inputs yields a distribution overhead destructive fire risk range of approximately 0.5x to 2x the point estimate. (See

Attach. B, WP027 for information for the key inputs and their confidence intervals.)

The input data used for Wildfire Risk Bow Tie model does not suffer from missing data due to improvements in PG&E ignition data quality control. The Bow Tie model is a closed-form expected-value calculation in which risk equals ignition frequency multiplied by consequence per ignition. As a result, the relationship between input uncertainty and output uncertainty is approximately linear. Because the model does not rely on iterative solvers or stiff differential equations, we do not believe that there is material uncertainty due to numerical instability.

g. Toy Problems

The Wildfire Bow Tie Toy Problem (Attach. B, WP027) provides the toy-model inputs, outputs, and calculations. The low, medium, and high cases are based on the lower bound of the 50 percent confidence interval, the point estimate, and the upper bound of the 50 percent confidence interval, respectively, for each key destructive fire risk input. The resulting distribution overhead destructive fire risk estimates range from approximately 0.5x to 2x the medium-case estimate.

h. Shelf-Life

This version of the Enterprise Bow Tie model is expected to be used until the 2028 model update for the 2028 RAMP and 2031-2034 GRC.

E. Key Decision-Making Metrics and Enterprise Diagrams (EUP Guidelines Section 2.7.3)

The Key Decision-Making Metrics (KDMMs) are defined to be the collection of top-level metrics that the Large Electrical Corporation proposes to use to evaluate the efficacy of an Undergrounding Project. These KDMMs are not influenced by risk attitudes, risk tolerances, opportunity costs or any other decision-making parameters. They do not reflect financial considerations and must be used alongside financialized metrics reported in Screen 2 and Screen 4 to evaluate projects. The KDMMs measure key elements of risk and can be substantiated by real-world observations.

The KDMMs will be used for approximating risk at the System-Level, Portfolio-Level, and individual Project-Level. A System-Level measurement accumulates information from the entire distribution system into a single number. A Portfolio-Level measurement accumulates information from every Circuit Segment on a Circuit which has one or more Confirmed Projects as well as their effects on the overall Circuit into a single number. A Project-Level measurement accumulates risk from all of the equipment on a single Circuit Segment.

The Large Electrical Corporation must include the seven mandatory KDMMs described below and has the option to include five additional KDMMs of its choosing.

a. The Large Electrical Corporation must include the following KDMMs:

- *i.* ***Overall Utility Risk:*** *A combined measure of Ignition Risk and Outage Program Risk that measures the total risk of wildfires and Outage Program Events related to wildfire risks. This is computed as the inner product of the likelihoods of adverse events and their consequences. This is an unweighted and unscaled calculation.*
- *ii.* ***Ignition Risk:*** *The measure of impacts from wildfire at a given location. This metric is the product of two factors: (1) the likelihood a wildfire will occur, and (2) the potential consequences of a wildfire originating from this location. This is an unweighted and unscaled calculation.*
- *iii.* ***Ignition Consequence:*** *The total anticipated adverse effects from a wildfire on each community it reaches. This metric considers the wildfire hazard intensity, the wildfire exposure potential, and the inherent wildfire vulnerabilities of communities at risk.*
- *iv.* ***Ignition Likelihood:*** *The likelihood of an ignition at a given location given a probabilistic set of environmental conditions.*
- *v.* ***Outage Program Risk:*** *The measure of reliability impacts from Outage Programs at a given location. This metric is the product of two factors: (1) the likelihood an Outage Program Event will be required due to environmental conditions exceeding design conditions, and (2) the potential consequences of the Outage Program for affected customers, considering exposure potential and vulnerability. This is an unweighted and unscaled calculation.*

vi. ***Outage Program Consequence:*** *The total anticipated adverse effects from an Outage Program for a community. This considers the Outage Program exposure potential and inherent Outage Program vulnerabilities of communities at risk.*

vii. ***Outage Program Likelihood:*** *The likelihood of an Outage Program being deployed at any given time, given a probabilistic set of environmental conditions. This measure should capture both the probability of an Outage Program Event(s) being initiated at given time and the length of time of those Outage Program Event(s).*

b. Up to five additional KDMMs proposed by the Large Electrical Corporation may also be included. For each additional KDMM, the Large Electrical Corporation must include the following information in the Overview Section of the Risk Modeling Methodology:

i. Provide a definition, numerical calculation, and units.

ii. Explain each proposed KDMM, including how the KDMM contributes to measuring Ignition Risk and/or Outage Program Risk.

iii. Report the proposed KDMMs at the same resolution and frequency as the required KDMMs.

The KDMMs are the top-level metrics used to evaluate the efficacy of an Undergrounding Project and to approximate risk at the System-Level, Portfolio-Level, and Project-Level. PG&E's EUP uses the seven required KDMMs listed in Section 2.7.3 of the EUP Guidelines.

Each of the 11,482 Circuit Segments that make up our system is unique in terms of its Wildfire Risk (likelihood and consequence) and Reliability Risk (likelihood and consequence). The system variation is reflected in the KDMMs.

PG&E uses KDMMs in many aspects of our decision-making. The KDMMs are used to establish Portfolio-Level Standards, Project-Level Thresholds and Project-Level Standards, all of which support our Plan Mitigation Objective. The six ignition and reliability risk KDMMs (numbers 2-7 described below) roll-up to the Overall Utility Risk KDMM which we consider when selecting Alternative Mitigations and prioritizing Projects for execution. PG&E's definition for each KDMM is provided below.

1. **Overall Utility Risk:** The combination of Ignition Risk and Outage Program Risk, along with considerations for climate change and escalation. This is represented as a dollar value and is an unscaled and unweighted value. (See Section D.5 of this chapter.)

2. **Ignition Risk:** Ignition Risks are Circuit Segment relative risk values based on the outputs of the WDRM. Ignition Risk is the product of the Probability of Ignition for an asset or location and the Wildfire Consequence at that location. The relative WDRM risk values are then calibrated against the absolute value of PG&E's Enterprise Risk Bow Tie for distribution Wildfire Risk. Ignition Risk is represented as a dollar value. (See Sections D.1 and D.2 of this chapter.)
3. **Ignition Consequence:** Ignition Consequence represents the mean expected damages conditional on an ignition occurring on a given Circuit Segment. It is calculated by dividing the monetized Ignition Risk by the Ignition Likelihood (i.e., the annual expected number of ignitions). (See Section D.2 of this chapter.)
4. **Ignition Likelihood:** Ignition Likelihood, also known as the Probability of Ignition, is aggregated for a Circuit Segment from the suite of distribution asset and contact from object event probability models. The event probability models predict the likelihood of an ignition for an asset or location over the length of one fire season. Ignition Likelihood is represented in ignitions per year. (See Section D.1 of this chapter.)
5. **Outage Program Risk:** This is the summation of EPSS Risk and PSPS Risk, representing the total monetized impact of outages caused by an Outage Program and is used to calculate the Overall Utility Risk. (See Sections D.3 and D.4 of this chapter.)
6. **Outage Program Consequence:** This quantifies the impact of an outage caused by an Outage Program on a Circuit Segment in dollars per outage minute and is used to estimate the customer impact in terms of the VoS lost for the count and type of customers impacted. (See Section C.1.b of this chapter.)
7. **Outage Program Likelihood:** This is defined as the expected number of outage minutes per year caused by an Outage Program on a Circuit Segment. It is calculated by summing the EPSS Likelihood and PSPS Likelihood. (See Section C.1.b of this chapter.)

The formulas for each KDMM for system aggregation and Portfolio-level aggregation are provided in the KDMM Formulas Workpaper.[187] The KDMM risk scores are in Chapter 9, Section E.4.

1. Enterprise Diagrams (EUP Guidelines Section 2.7.3.1)

The Large Electrical Corporation must provide one or more entity relation diagram(s) of the system(s) used for quantifying Ignition Risk and one or more entity relation diagram(s) of the system(s) used for quantifying Outage Program Risks.

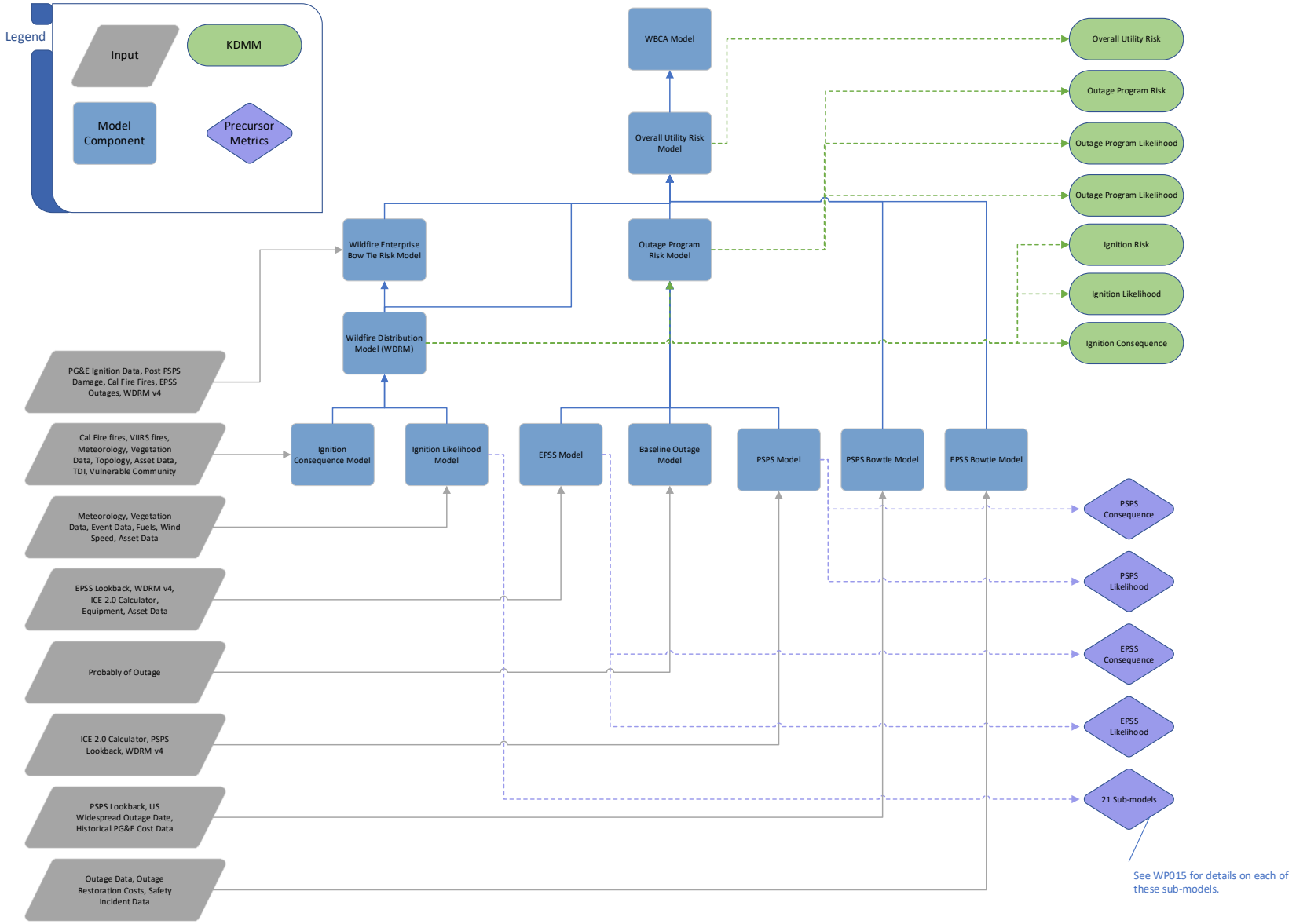
Each diagram must show how input data feeds into independent sub-models and identify the KDMMs, and all precursor calculations used in generating each KDMM. A precursor calculation is an intermediate modeling value with explainable meaning that is computed from the input data and determined in the process of computing the KDMM. For example, an unscaled consequence score is considered a precursor calculation for a scaled risk score, but an intermediate activation value of a neural network is not considered a precursor. Similarly, if a risk score is normalized by distance (i.e. units of risk per mile), then the raw risk score is considered to be a precursor calculation.

The enterprise diagrams show how data feeds into the sub-models and models that compute the KDMMs. The diagrams show input data, model components, KDMMs and precursor metrics. The precursor calculation is an intermediate modeling value that is computed from the input data and determined in the process of computing the KDMM:

Figure 7-2 is the Overall Utility Risk KDMM Diagram.

[187] Attach. B, WP021.

FIGURE 7-2:
OVERALL UTILITY RISK KDMM DIAGRAM



F. Model Risk Landscape (EUP Guidelines Section 2.7.4)

The Model Risk Landscape is the collection of all inputs, outputs and intermediate calculations used in the Risk Modeling Methodology. This includes all KDMMs, their precursor calculations, and any additional numerical evidence that the Large Electrical Corporation uses to evaluate or report the risk reduction of an Undergrounding Project or Alternative Mitigation. The Large Electrical Corporation must incorporate the elements of the Model Risk Landscape in its narrative supporting the Risk Modeling Methodology.

All claims involving the comparative risks of individual Undergrounding Projects must be substantiated by numerical comparisons between Model Risk Landscapes using the same version and calibration of the Risk Modeling Methodology.

A Model Risk Landscape is determined by these four elements:

1. *The model version must indicate a unique configuration of the models as detailed in Section 2.7.5.2 of these Guidelines.*
2. *The calibration settings must uniquely identify the collection of non-project related input data fed into the models or used in historical tables.*
3. *The project list must refer to all projects that the model is considering in a specific evaluation for this measurement of Model Risk Landscape.*
4. *The forecast time must indicate what instantaneous time or accumulative period the model is evaluating.*

PG&E explains how the elements of the model risk landscape are incorporated into our Risk Modeling Methodology in Section C.1, Overview of Risk Modeling Methodology, above. Each element of the model risk landscape is outlined below:

(1) **Model configuration:** See Section I (Version and Calibration Changes) below for further details on PG&E's response to Section 2.7.5.2 of the Guidelines.

(2) **Calibration settings:** See the Model Report Chapters (Sections D.1–D.7) for comprehensive details regarding the input data incorporated into the models and the historical tables utilized.

(3) **Project list:** See Section I (Version and Calibration Changes) and Core Capability 6 (Section G.6) below for details of PG&E's Baseline approach.

(4) **Forecast time:** See Core Capability 4 (Section G.4) below.

G. Required Core Capabilities for Risk Modeling Methodology (EUP Guidelines Section 2.7.5)

Core Capabilities are defined as a set of required use-cases that the Large Electrical Corporation's Risk Modeling Methodology must be able to achieve to make quantitative arguments about the risk reduction of Undergrounding Projects and Alternative Mitigations. The Large Electrical Corporation must detail the formal quantitative procedure for achieving each of the following Core Capabilities:

a. Project-Level Risk Analysis;

b. Aggregate Risk Analysis;

c. Ignition Risk and Outage Program Risk as Separate and Collective Risks;

d. Approximating Future Risks and Accumulation of Ignition Risk and Electrical Reliability over time;

e. Accounting for Undergrounding Projects with Multiple Mitigations and Subprojects;

f. Establishing Baselines and Historical Calibrations; and

g. Comparisons with Alternative Mitigation Strategies.

The Large Electrical Corporation must also list any additional workflows that are critical for evaluating the effectiveness and efficiency of its EUP.

For each capability, the Large Electrical Corporation must provide a narrative description, explicit formulas, and example calculations demonstrating how the capability is achieved. These example calculations may use synthetic inputs, but all formulas, input/output scaling and user parameters must be the same as those used in the Risk Modeling Methodology. The Large Electrical Corporation may include additional workbooks with the Model Report that demonstrate these calculations.

The seven Core Capabilities are a set of required use-cases that PG&E uses to make quantitative arguments about the risk reduction of undergrounding and Alternative Mitigations. Each is described below. To comply with the two-page limit for each core capability at page B-4 of the EUP Guidelines, we reference relevant discussions in other sections of the EUP or in supporting workpapers instead of repeating the discussion here.

1. Core Capability 1: Project Level Risk Analysis

The Large Electrical Corporation must demonstrate that its framework can analyze risk reduction of projects in its Portfolio both separately and collectively. For each project, the Large Electrical Corporation must conduct a Collective Analysis, a Separate Analysis, and an Ablation Analysis. Each study will report these results at the Portfolio-Level and Project-Level.

a. The Collective Analysis describes the risk reduction of a single Undergrounding Project in combination with the rest of the Undergrounding Projects that are in the same Portfolio and details the effects of the specific Undergrounding Project on Circuit(s) as well as the entire system. It is reported for each Undergrounding Project at the Portfolio-Level and Project-Level.

b. The Separate Analysis measures the risk reduction of this Undergrounding Project if it was the only Undergrounding Project in the Portfolio and is reported at the Portfolio-Level and Project-Level.

c. The Ablation Study details the effects if this Undergrounding Project is NOT included in the Portfolio at both the Portfolio-Level and Project-Level.

The Large Electrical Corporation must provide examples of the computation in the narrative section of the EUP and explicitly state unit-conversion factors used to assess Project-Level risks.

a. Collective Analysis

As part of the Collective Analysis, PG&E assesses Undergrounding Projects at both the Project-Level and at the Portfolio-Level. PG&E understands “Portfolio-Level” to include every Circuit Segment on each Circuit which has one or more Confirmed Projects, and “Project-Level” to include only the individual confirmed Project.

At the Project-Level, this resembles the Collective residual risk associated with each of the confirmed Undergrounding Projects. Given PG&E models Project risk independently with upstream and downstream effects already incorporated in the modelled risk outputs, Collective residual risk at the Project-Level is synonymous with Separate residual risk at the Project-Level. The risk impact is the same primarily due to the method PG&E uses to estimate Overall Utility Risk, which subsumes the downstream impacts from a weather event and resulting customer outages in the risk calculation for each Circuit Segment. Because each risk model already attributes downstream customer impacts to each Circuit Segment's risk value, there are no

additional cross-project or network interaction effects that need to be separately accounted for in the Collective Project-Level analysis. This logic is the same for Wildfire Risk, PSPS Risk, EPSS Risk and Overall Utility Risk.

At the Portfolio-Level, the Collective residual risk is the sum of all residual risks associated with all Circuit Segments at the Portfolio-Level, assuming all confirmed Undergrounding Projects are mitigated. Based on Progress Report 0, this means 28 Undergrounding Projects will provide a residual risk value while the remaining Circuit Segments at the Portfolio-Level will provide unmitigated risk values.

b. Separate Analysis

As part of the Separate Analysis, PG&E assesses Undergrounding Projects at both the Project-Level and at the Portfolio-Level.

The Separate Analysis at the Project-Level calculates the residual risk for each Undergrounding Project by applying the applicable mitigation effectiveness value to the Project's unmitigated risk. The resulting value represents the residual risk remaining after the Project is mitigated. In effect, the Separate Analysis at the Project-Level evaluates each Undergrounding Project independently, without considering the residual risk associated with other Circuit Segments.

The Separate Analysis at the Portfolio-Level calculates the Portfolio-Level residual risk if the Undergrounding Project in question were the only Project mitigated. Accordingly, the Project under evaluation contributes its residual risk after mitigation, while all other Circuit Segments at the Portfolio-Level contribute unmitigated risk values.

c. Ablation Analysis

As part of the Ablation Analysis, PG&E assesses Undergrounding Projects at both the Project-Level and at the Portfolio-Level.

Ablation at the Project-Level represents the residual risk associated with each individual Undergrounding Project if that Project were not mitigated. Consistent with PG&E's risk modeling approach described in Section G.1.a (Collective Analysis), this value is equivalent to the

Project's unmitigated risk because no mitigation is assumed for the Project being evaluated, and mitigation of other Undergrounding Projects does not affect its risk.

Ablation at the Portfolio-Level calculates the Portfolio-Level residual risk if the Undergrounding Project in question were the only confirmed Undergrounding Project not mitigated.

PG&E provides supporting formulas for the Collective, Separate and Ablation analysis in Attach. B, WP008 (Core Capability 1: Supporting Formulas.)

2. Core Capability 2: Aggregate Risk Analysis

The Large Electrical Corporation must detail, in narrative form, its method for evaluating risk metrics at the Portfolio-Level and System-Level. For each KDMM, the Large Electrical Corporation must provide an explanation of its aggregation process. This narrative must include a description of the process the Large Electrical Corporation uses for the summation or aggregation of Circuit/Circuit Segment risks. This may include linear and/or non-linear processes if appropriately justified.

The Large Electrical Corporation must also demonstrate how it evaluates the effectiveness of multiple projects simultaneously for both Ignition Risk and Outage Program Risk.

PG&E evaluates each KDMM at the Circuit Segment level and aggregates the results to produce Portfolio-Level and System-Level metrics. The methodology for evaluating and aggregating each KDMM follows:

- **Evaluating Risk at Circuit Segment Level:** KDMMs are modeled and measured at the Circuit Segment level. The evaluation of each KDMM is also conducted at this level, with mitigation effectiveness applied directly to the risk metric associated with each individual Circuit Segment. Each Circuit Segment is evaluated independently, and the resulting risk metrics are subsequently aggregated to generate Portfolio-Level and System-Level results.
- **Linear KDMMs:** Overall Utility Risk, Ignition Risk, Ignition Likelihood, Outage Program Risk, and Outage Program Likelihood are aggregated using linear summation.
    - At the Portfolio-Level, each risk metric is calculated as the sum of values across all confirmed Undergrounding Projects along

with the sum of values across all other Circuit Segments that are not confirmed Undergrounding Projects but are considered as part of the Portfolio-Level metric. PG&E's understanding of Portfolio-Level is described in Core Capability 1.

    - At the System Level, each risk metric is calculated by summing Circuit Segment values across the entire system.

- **Non-Linear KDMMs:** Ignition Consequence and Outage Consequence are calculated by dividing the corresponding risk by the associated likelihood. This methodology is consistent across pre-mitigated, mitigated or residual risk values and is applied for both Portfolio-Level and System-Level aggregation. For example, if the Portfolio-Level aggregated post-mitigation Ignition Risk is $2 million and the Ignition Likelihood is 0.02 ignitions, then the following calculation would define the Portfolio-Level Ignition Consequence: *$2 million / 0.02 ignitions* = *$100 million per ignition.*

PG&E provides supporting formulas for the KDMM aggregation process in Attach. B, WP009 (Core Capability 2: Supporting Formulas.)

3. Core Capability 3: Ignition and Outage Program Risk as Separate and Collective Risks

The Large Electrical Corporation must detail its method for evaluating Ignition Risk and Outage Program Risk through separated and combined metrics. The Large Electrical Corporation must demonstrate its framework for performing separate and collective analysis of Ignition Risk reduction and reliability benefits from reduced Outage Program Risk. The Large Electrical Corporation must demonstrate that its analysis for each of these metrics can be performed both independently and collectively.

The Large Electrical Corporation must additionally describe its method for balancing the trade-off between Ignition Risk and Outage Program Risk in its modeling. That is, the Large Electrical Corporation must explicitly define how it computes Overall Utility Risk as a factor of both Ignition Risk and Outage Program Risk and describe how each of these factors play a role in its process for selecting projects. The Large Electrical Corporation must explicitly state the value of any unit-conversion factors used in this computation and explain how they arrived at these value(s).

Lastly, the Large Electrical Corporation must describe the model gap between the modeled trade-off and the Large Electrical Corporation's real-world approach to limiting ignitions through Outage Programs. That is, the Large Electrical Corporation must describe how its modeled process differs from the real-world process used to intentionally deenergize lines during high-wind events (such as during a Public Safety Power Shutoff) and determine the use of fast trip settings.

a. Evaluation of Ignition and Outage Program Risks Through Metrics

PG&E evaluates Ignition Risk at the Circuit Segment level using separate metrics for wildfire safety, reliability and financial impacts. For Outage Program Risk, we evaluate the effects of EPSS and PSPS separately, considering likelihood and consequences. Circuit Segment risk combines Ignition and Outage Program Risk into OUR values. Ignition Risk uses safety, reliability and financial impact values from our Enterprise Risk Bow Tie model. Safety is monetized using the Value of Statistical Life (VSL). Wildfire Reliability is based on the VoS from the ICE Calculator. Financial values are an output of acres burned and structures destroyed. The WBCA allocates Bow Tie Wildfire Risk to Circuit Segments based on WDRM risk points and evaluates each metric independently, calculating them separately and summing them for combined metrics. Supporting formulas for Ignition Risk and Outage

Program Risk, including separate and combined analysis are provided in Attach. B, WP010 (Core Capability 3: Supporting Formulas).

b. Framework for Separate and Collective Analyses of Ignition Risk Reduction and Reliability Benefits From Outage Program Risk

PG&E conducts both Separate and Collective analyses of Ignition and Outage Program Risk reduction in our WBCA model. Risk reduction is calculated at the Circuit Segment level with no dependencies on other Circuit Segments. The Separate and Collective analyses consider the mitigation effectiveness as a percentage multiplied by the risk on a Circuit Segment.

c. Trade-off Between Ignition Risk and Outage Program Risk

EPSS and PSPS are operational mitigations that reduce the likelihood of ignitions by limiting exposure to energized equipment under elevated risk conditions. These programs also introduce Outage Risk in the form of customer outages that otherwise would not have occurred. PG&E therefore evaluates the wildfire and outage components separately. Wildfire Risk is represented using a WLDFR Bow Tie baseline that already incorporates the Wildfire Risk reduction attributable to EPSS and PSPS, while EPSS and PSPS outage risks are estimated using the OPRM. These components are then combined to calculate the Overall Utility Risk. An 80 percent decrease in Ignition Risk and a 46 percent decrease in Ignition Likelihood associated with EPSS and PSPS are embedded in the Wildfire Risk baseline used for Overall Utility Risk. The supporting formulas in Core Capability 3 Workpaper, Attach. B, WP010, detail the method for deriving the Wildfire Risk baseline.

This approach preserves visibility into the effects of EPSS and PSPS without double-counting their wildfire benefit. The wildfire baseline reflects the reduced risk condition after those operational mitigations are considered, while the outage component reflects the reliability impact created by those same programs. Overall Utility Risk therefore represents the combined utility risk associated with the

post-EPSS/post-PSPS wildfire risk plus the modeled outage risks from EPSS and PSPS.

PG&E recognizes that EPSS and PSPS are relatively new operational programs, and their effectiveness assumptions remain subject to significant uncertainty because recorded performance data are limited across the full spectrum of adverse operating conditions. PG&E also recognizes that these mitigations are not permanent, and the Commission has instructed the utilities to limit their use and rely on them as a "measure of last resort."[188] (See discussion in Chapter 1, Section D. 1.) For this reason, PG&E will continue to prioritize selection of Projects for permanent mitigations based on Wildfire Risk ranking rather than Overall Utility Risk value. This prioritization reflects the potential for ignitions to produce disproportionately catastrophic consequences relative to other utility risks, even where operational mitigations are assumed to reduce baseline Wildfire Risk.

d. Modeling Gaps Associated With Outage Programs

Gaps between modeled Outage Programs and actual decision-making are inherent in any forward-looking model. This is particularly true for models for programs such as PSPS and EPSS, which are activated in response to dynamic, location-specific, and time-sensitive weather conditions.

PG&E's PSPS Risk Model relies on historic data and standardized assumptions to approximate future risk outcomes. Risk is modeled using historic data, including weather patterns and PSPS event footprints, and PSPS activation protocols to estimate the likelihood and consequences of de-energization at the Circuit Segment level. This approach provides a consistent, repeatable, and transparent basis for evaluating long-term trade-offs between Wildfire Risk reduction and customer reliability.

Similarly, the EPSS Risk Model is a simplified, standardized representation of the incremental outage risk from fast-trip settings. The

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[188] D.21-06-034, p. 61; see also D.19-05-042, p. 69 (PSPS should be considered a mitigation of "last resort.").

model is calibrated with historic equipment fault probabilities and outage duration assumptions to estimate the expected frequency and consequence of sustained outages when fast-trip settings are enabled. These inputs provide a stable, analytically consistent basis for long-term planning; however, they are inherently backward-looking and may not persist as equipment performance, operating conditions, system configuration, and restoration practices evolve.

4. Core Capability 4: Approximating Future Risks and Accumulation of Ignition Risk and Outage Program Risk Over Time

The Large Electrical Corporation must detail its method for evaluating Ignition Risk and Outage Program Risk at future dates and the accumulation of Ignition Risk and Outage Program Risk over time. The Large Electrical Corporation must report instantaneous and cumulative risk and reliability scores at 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 15, 20, 25, 30, 35, 40, 45, 50, and 55 years into the future for all Confirmed Projects. Model Year 0 is defined to begin on the date the Large Electrical Corporation designates as the start date of the EUP (as set forth in the Target/Timeline Table), and subsequent times are measured at a fixed timeline from the same date.

The Large Electrical Corporation must describe how it uses estimated Project timelines to model the reduction of risk and increase in reliability over time. For Undergrounding Projects, this timeline must include the estimated time for the Project to acquire new rights-of-way, easements, permits, and CEQA review, if any. For non-undergrounding work, this timeline must use an estimate specific to the type of work using assumptions about the start time and construction time that are reasonable and consistent with the work being performed and assuming that the work will begin and be completed as soon as practicable. The Large Electrical Corporation must detail how these Projections reflect its modeling of climate change as described in Core Capability 6.

If any discount rates are employed in the calculation of any KDMM, the Large Electrical Corporation must list them and explain their origin. If the discount rates change over time, the Large Electrical Corporation must explain how they change and why these changes are warranted. Changes must be in line with the CPUC Risk-based Decision-Making Framework Proceeding (Rulemaking 20-07-013 or its successor proceeding).

a. Methodology for evaluating Ignition Risk and Outage Program Risk at Future Dates and Over Time

The process begins by evaluating the 2028 / Model Year 0 pre mitigation and residual (post mitigation) Ignition Risk and Outage Program Risk of the Circuit Segment corresponding to the Confirmed

Project. The instantaneous risk for each Model Year is evaluated by multiplying either pre mitigation or residual risk by the climate factor for each model year. The pre mitigation risk values are used in the years up to and including the energization year, and residual risk values are used in years beyond the energization year. The cumulative risk is then evaluated for each Model Year by summing the instantaneous risk values from Model Year 0 through the current Model Year.

Our Core Capability 4 Workpaper (Attach. B, WP011) provides formulas used for evaluating Ignition and Outage Program Risk at future dates, the accumulation of these risks over time, and discount rate details. PG&E reports on instantaneous and cumulative risk and reliability scores at 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 15, 20, 25, 30, 35, 40, 45, 50 and 55 years for all confirmed Projects beginning with Year 0.

For Core Capability 4, the baseline 2028 KDMM values are escalated for climate impacts and adjusted for inflation to estimate nominal dollar values in future years. Discount rates are not used in calculating the nominal KDMM values evaluated under Core Capability 4. Discount rates are applied only when calculating present values, such as those used in Benefit-Cost Ratio (BCR) analyses. For transparency, WP011 includes the discount rates used in BCR evaluations. PG&E relies on the Weighted Average Cost of Capital (WACC) as its primary discount rate. The WACC is assumed to remain constant over the expected service lives of overhead and underground assets. To ensure the analysis reflects current financing assumptions, PG&E may update the WACC discount rate as part of future WBCA model releases if warranted, provided any such changes are consistent with the CPUC Risk-Based Decision-Making Framework Proceeding (Rulemaking 20-07-013 or its successor proceeding). PG&E also reports the Societal and Hybrid discount rates required by Safety Policy Division (SPD) guidance.

b. Estimated Timelines Used to Model Risk Reduction

Estimated Project timelines are provided in Chapter 4, Section D.1.b for undergrounding and Chapter 4, Sections D.2.b and D.3.b for non-EUP Projects including overhead hardening and line removal

Projects. PG&E models risk reduction and reliability improvements over time based on when underground lines are energized. We consider Ignition and Outage Program Risk reduction achieved when all Subprojects on a Circuit Segment are complete. Project timing may also influence Prioritization.

PG&E uses each Project's estimated completion year to model the timing of risk reduction and reliability benefits for EUP tracking and reporting. For the WBCA analysis, all Circuit Segments are evaluated using a common 2028 base year for comparability and to avoid distortion from climate Projections and discounting assumptions. For in-flight Projects, risk calculations are updated as Project definitions mature and accurate electric end dates are refined.

c. How Projections Reflect Modeling of Climate Change

Climate change is incorporated into WBCA risk benefits through annual climate multipliers. (See Attach. B, WP006.) Consistent with Core Capability 6, PG&E uses two climate variables: a FWI multiplier and a Heat Day multiplier. The FWI multiplier reflects projected changes in wildfire conditions and is applied to Wildfire, EPSS, and PSPS risks. The Heat Day multiplier reflects projected changes in sustained heat exposure and equipment performance and is applied to Wildfire, EPSS, and baseline Reliability risks. PG&E develops annual climate multipliers through 2092 and applies them to risk values in each model year. Public safety risk is not adjusted for climate change.

5. Core Capability 5: Accounting for Undergrounding Projects with Multiple Mitigations and Subprojects

The Large Electrical Corporation must detail its method for evaluating Ignition Risk and Outage Program Risk for Undergrounding Projects that are completed in stages or have multiple mitigations on a single Circuit Segment. This description must contain explicit formulations and justification for any weighting employed in the computed risk reduction or allocation.

For Circuit Segments containing multiple mitigations (such as a portion of the Circuit Segment undergrounded, and another portion of the same Circuit Segment replaced with covered conductor), the Large Electrical Corporation must demonstrate how it models the risk-reduction of the overall Project as well as how that risk reduction can be allocated between the different Subprojects. This must include an assessment of what equipment on the previously existing Circuit Segment will be removed, replaced, or refurbished at what specific time as a part of a Subproject. In this assessment, each individual piece of equipment must be assigned to a single Subproject and cannot be assigned to multiple Subprojects. The Large Electrical Corporation must also comment on any modeling gap between their allocation scheme and the real-world risk profile of the Circuit.

The Large Electrical Corporation must develop a Projected timeline for completion of each Subproject and factor this into its overall Risk Modeling Methodology. Ignition Risk may only be reduced in the forecasted modeling after an overhead line is Projected to be deenergized. Similarly, Outage Program Risk may only be forecasted to be reduced once the new line is Projected to be energized. This requirement only directly applies to Screen 3 and Screen 4. Information on Subprojects in Screen 2 must be in accordance with the CPUC Risk-based Decision-Making Framework Proceeding (Rulemaking 20-07-013 or its successor proceeding).

Additionally, the Large Electrical Corporation must demonstrate a method to apportion overall risk reduced by an Undergrounding Project with multiple mitigations to the contribution from each mitigation type. For example, if the Large Electrical Corporation envisions a Confirmed Project with some portions of Undergrounding, covered conductor installation, and line-removal, it must be able to determine the overall risk reduction of the Confirmed Project and the amount of that overall risk reduction due to each of the non-Undergrounding strategies. The apportionment methodology must be consistent across all Undergrounding Projects. The sum of risk reduced by each Subproject in a given Confirmed Project must equal the risk reduction of the Confirmed Project itself.

a. Risk Evaluation for Projects That Are Completed in Stages or Have Multiple Mitigations on a Single Circuit Segment

PG&E allocates risk reduction for Undergrounding Projects that are completed in stages or have multiple mitigations on a single Circuit Segment. For Circuit Segments with multiple mitigations, we model the

risk reduction of the overall Project by first determining that total risk on the Circuit Segment and then allocating the risk reduction among the Subprojects. Risk reduction is allocated among the Subprojects on a pro-rata basis per mile considering the effectiveness of each mitigation (See Attach. B, WP012). We calculate the total risk reduced on a Circuit Segment by summing the risk reduction of each Subproject.

For Projects completed in stages, PG&E counts the risk reduction when the assets become operational. For Ignition Risk, this occurs when the old overhead line is deenergized and for Outage Program Risk, this occurs when the new underground line is energized.

b. Weighting in Risk Reduction or Allocation in Models

In the PSPS OPRM, weighting is applied to critical facilities and customers classified as life support, medical baseline, or low income to reflect the greater impact of an outage on these customers. To avoid inflating the Overall Utility Risk, the PSPS Outage Program Risk is normalized after applying this weighting so the total PSPS Outage Program Risk is the same before weighting and the effect is a redistribution of risk to critical customers.

c. Equipment Assessments in Undergrounding Projects and Modeling Gaps

PG&E removes and replaces all overhead primary voltage distribution system equipment during the construction of an Undergrounding Project. PG&E does not conduct an equipment assessment because all existing equipment is removed. PG&E assesses secondary and service lines during the Undergrounding Project design phase.

For an Overhead System Hardening Project, we assess existing poles to determine if any can meet requirements for overhead hardened lines. Non-compliant poles are replaced. PG&E also assesses other equipment such as regulators, fuses, switches, and other devices. Equipment that meets PG&E's standards is reused while equipment that does not meet our standards is removed or replaced. PG&E does not include refurbished equipment in an overhead hardening design

package. However, PG&E may remove and refurbish equipment in good condition and return it to working stock for use on a future project. Equipment is removed when it is no longer used or needed.

WDRM v4 is based on the condition of the grid on January 1, 2023. Equipment replaced after that date is reflected in PG&E's GIS but is not in the WDRM v4 baseline. The data in each Progress Report will show each asset in the asset data set assigned to a single Subproject.

d. Project and Subproject Timelines

Timelines for each individual Subproject are not integrated into the risk modeling methodology considered in Screen 3. Dividing a Project into Subprojects facilitates scope delineation between mitigation types. Project timing does not influence Project or mitigation selection. Rather PG&E first selects Projects and Alternative Mitigations in Screen 3 and subsequently, in Screen 4, prioritizes Projects by considering wildfire risk reduction, reliability benefits, Cost Efficiency and public safety. This methodology is outlined in Chapter 3, Section D.4.

We will manage our Portfolio to meet Portfolio-Level constraints such as cost recovery requirements and EUP targets and plan tracking objectives. To meet these constraints, PG&E may evaluate factors such as Project and Subproject timing and schedules. However, PG&E does not model or account for forecasted risk reduction in our modeling methodology used in either Screen 3 or Screen 4.

e. Apportioning Risk Reduction in Projects with Multiple Mitigations

PG&E describes our method for apportioning overall risk reduced by a Project with multiple mitigations in Section G.5.a above.

6. Core Capability 6: Establishing Baselines and Historical Calibrations

Modeling Methodology is evaluated with up-to-date information that accurately reflects the Large Electrical Corporation's understanding of the risk on the system. Additionally, the Large Electrical Corporation must demonstrate that comparisons between Undergrounding Projects and Alternative Mitigations are made on a statistically consistent scale.

To do this, the Large Electrical Corporation must develop a system to record Baselines and historical model calibrations. A new Baseline must be recorded by the Large Electrical Corporation at least once per calendar year. This new Baseline must account for all physical changes to the electrical distribution infrastructure performed during that year, through the EUP or any other mechanism.

To establish an initial Baseline, the Large Electrical Corporation must model the risk landscape assuming that no EUP Undergrounding Projects are constructed. This Baseline modeling must include any non-EUP wildfire mitigation activity in Tier 2 or 3 HFTDs. In subsequent Baselines, the Large Electrical Corporation must include activity outside of the EUP program that the Large Electrical Corporation has initiated or completed since the establishment of the previous Baseline.

This modeling will attempt to account for climate change. Baselines must be measured and reported at the same cadence as other risk model landscape components at 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 15, 20, 25, 30, 35, 40, 45, 50, and 55 years.

Each Baseline must indicate the version of the modeling system and the model calibration(s) that were used to evaluate it. The Baselines must also indicate the date the Baseline was created, and the naming scheme of the Baselines must be consistent across the lifetime of the EUP. Any comparison of an Undergrounding Project or Alternative Mitigation to a Baseline must indicate what Baseline the comparison is being made to.

For Project-Level comparisons, such as the evaluation of the Project-Level Standard, the Baseline also establishes the pre-mitigation Circuit Segment length and alignment on which to make the future comparisons.

PG&E's approach for establishing Baselines and historical calibrations is detailed below and in the other referenced sections of the EUP.

a. Updating Risk Models

Information regarding model updates and calibration is provided in Chapter 8, Model Retention and Update Schedule**.** Information about anticipated updates to the models is also provided above in in this chapter (see Section D, Model Reports (subsection h "Shelf Life")).

b. Alternate Mitigations Comparisons are Statistically Equivalent

PG&E uses the same method to calculate Overall Utility Risk for all Circuit Segments and anchors to the same Baseline for all risk calculations ensuring that all Undergrounding Projects and alternative measure comparisons are made on a statistically equivalent scale.

c. System to Record Annual Baselines and Model Calibrations

PG&E will release a new version of the WDRM in alignment with WMP cycle beginning in 2028. Due to the complexity of the model, recalibration does not occur between model versions. The OPRM is directly dependent on WDRM data and is updated with new WDRM releases. As a result, core risk models cannot be meaningfully updated between WDRM versions; instead, annual Baselines will occur downstream of the models, through a postprocessing adjustment.

PG&E will update the Baseline annually by tracking the risk reduction from the EUP and non-EUP system hardening work, as described Core Capability 5, calculated at the Circuit Segment level and aggregated at the system level for reporting. Despite annual Baseline updates, all mitigation decision-making will rely on the WDRM v4 until the model is updated, after which decisions will be based on WDRM v5.

d. Establishing and Updating the Baseline

The initial Baseline is based on a snapshot of PG&E's electric grid as of January 1, 2023, before the EUP Projects could be constructed. (See Chapter 3, Section D.3.a.11.) In subsequent annual Baselines, PG&E will account for the change in risk reduction from EUP and non-EUP system hardening Projects by calculating the change in risk described in Section D.6.c. These calculations are conducted outside of the WDRM and OPRM to maintain a stable Baseline for comparing mitigations as WDRM and OPRM inform forward-looking decision-making and are not intended for retrospective risk calculations. Changes to equipment that do not impact risk (i.e., changing a transformer with a transformer that is equally as effective) will not be reflected in the Baseline update.

PG&E will update the risk Baseline once per year by subtracting the risk reduction achieved from all completed system hardening Projects regardless of the regulatory proceeding in which it was approved.[189] For Circuit Segments that are only partially undergrounded, risk reduction is applied proportionally based on the portion of the Circuit Segment that is undergrounded.

e. Modeling to Account for Climate Change and Baseline Reports

PG&E describes how we account for climate change in Section G.4.c. Cumulative risk reduction is calculated at intervals of 0,1, 2, 3,4, 5, 6,7,8,9, 10, 15, 20, 25, 30, 35, 40, 45, 50 and 55 years by applying the climate factor to each model year and summing the individual values. For example, cumulative risk reduction at Model Year 15 is the sum of individual risk reduction values for each Model Years 1-15. Supporting formulas demonstrating how we account for climate change are also in Attach. B, WP013.

f. Baseline Versioning

Chapter 8, Section C.4 outlines the framework for the model versioning and calibrating including naming conventions and timing of model versions and calibrations applicable throughout the EUP. Beginning in 2028, the WDRM and OPRMs will be refreshed in alignment with the WMP. Between WDRM versions, annual Baselines and calibrations will be applied via postprocessing adjustments, enabling reprioritization of Circuit Segments and Portfolios without changing the core model.

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189 PG&E's assumptions regarding mitigation effectiveness and risk reduction for each of PG&E's non-EUP system hardening programs are addressed in Chapter 4, Section D.

7. Core Capability 7: Comparisons with Alternative Mitigation Strategies

The Large Electrical Corporation must demonstrate its method for comparing an Undergrounding Project with Alternative Mitigations as detailed in Section 2.7.10. Additionally, if the Undergrounding Project consists of both Undergrounding and overhead hardening Subprojects, as described in Core Capability 5, only the risk reduction due to the Undergrounding Subprojects may be counted toward the Portfolio-Level Standards, Plan Tracking Objectives, and Plan Mitigation Objective. All the Subprojects (including non-undergrounding Subprojects) may be counted toward the Project-Level Standard.

Further details on the required comparisons are given in Section 2.7.10.

PG&E demonstrates our method for comparing undergrounding to Alternative Mitigations and Additional Comparisons in Chapter 3, Section D. As required, only the risk reduction due to the Undergrounding Subprojects is counted toward the Portfolio-Level Standards. EUP Chapter 7 outlines the decision criteria (BCR analysis) described in the Project Acceptance Framework.

In addition to the BCR analysis, PG&E also considers constructability issues during Project scoping that compare the effectiveness and/or feasibility of undergrounding to Alternative Mitigations. For example, during a scoping meeting, PG&E's grid design engineers determine if there are field constraints that would make undergrounding infeasible or very expensive such as overhead lines crossing a large waterway or a ravine that may require a change from planned undergrounding to overhead hardening for a section of the Circuit Segment.

PG&E provides supporting formulas demonstrating how we compare undergrounding to Alternative Mitigations in Core Capability 7: Supporting Formulas, Attach. B, WP014.

H. Model Inputs and Considerations (EUP Guidelines Section 2.7.5.1)

The Large Electrical Corporation must provide a comprehensive summary of all model inputs used to compute each metric included in its Model Risk Landscape. This summary includes all real-world observations, KDMMs, precursor calculations and any other metric reported in the EUP or Portfolio Coversheet.

For each input category, the Large Electrical Corporation must formally define the term and describe the original data sources and the purpose of including these factors in the overall Risk Modeling Methodology in a narrative format of at most one page per requirement.

At minimum, the model inputs must include:

a. ***Equipment / Assets*** *(e.g., type, age, inspection, maintenance procedures, etc.)*

b. ***Topography*** *(e.g., elevation, slope, aspect, etc.)*

c. ***Weather*** *(at a minimum this must include statistically extreme conditions based on weather history and seasonal weather)*

d. ***Vegetation*** *(e.g., type/class/species/fuel model, canopy height/base height/cover, growth rates, moisture content, inspection, clearance procedures, etc.)*

e. ***Climate change*** *(e.g., long-term changes in seasonal weather; statistical extreme weather; impact of change on vegetation species, growth, moisture, etc. At a minimum, this must include adaptations of historical weather data to current and forecasting future climate.)*

f. ***Social vulnerability*** *(e.g., socioeconomic factors, etc.)*

g. ***Physical vulnerability*** *(e.g., people, structures, critical facilities/infrastructure, etc.)*

h. ***Coping capacities*** *(e.g., limited access/egress, etc.)*

PG&E provides a comprehensive summary of the model inputs used to compute each metric included in our Risk Model Chapters Sections D.1 to D.7 of this chapter.

PG&E describes the inputs into our WDRM, OPRM, WBCA and Enterprise Risk Bow Tie Model below. Please note, the specific input terms listed in Section 2.7.5.1 of the EUP Guidelines do not necessarily apply to each of PG&E's models. Therefore, we have listed the actual inputs into each risk model as opposed to limiting the inputs to those described in Section 2.7.5.1 of the EUP Guidelines.

Model input categories for PG&E's risk models are defined below:

I. **Equipment/Assets:** Data describing the characteristics, condition, configuration, maintenance history, operational status, and location of electric system assets.

II. **Topography:** Data describing terrain and landscape characteristics that influence wildfire behavior, asset exposure, accessibility, and mitigation implementation.

III. **Weather:** Meteorological observations and derived metrics used to characterize environmental conditions affecting asset performance, wildfire ignition potential, outage occurrence, and consequence severity.

IV. **Vegetation:** Data describing vegetation characteristics, condition, distribution, and behavior that may interact with electric infrastructure or influence wildfire risk.

V. **Climate change/Climate assumptions:** Data, projections, and assumptions used to represent the impact of changing climate conditions on future risk.

VI. **Social vulnerability:** Data describing socioeconomic characteristics that may influence a community's ability to prepare for, respond to, and recover from wildfire or outage events.

VII. **Physical vulnerability:** Data describing the people, structures, facilities, infrastructure, and customers that may be affected by wildfire or outage events.

VIII. **Coping capacities:** Data describing the ability of individuals, communities, and infrastructure systems to withstand, respond to, and recover from disruption events.

IX. **Input model:** Outputs from validated models that serve as inputs to downstream analyses, including probability, consequence, or forecasting metrics.

X. **Financial:** Data used to quantify the monetary impacts of wildfire and reliability risk outcomes.

XI. **Cost Assumptions:** Assumptions and datasets used to estimate capital, operational, maintenance, restoration, and program implementation costs.

XII. **Financial Assumptions:** Economic and regulatory assumptions used to support long-term planning and valuation analyses.

XIII. **Mitigation Effectiveness Datasets:** Datasets used to estimate the degree to which mitigation programs reduce wildfire risk, outage risk, or other adverse outcomes.

XIV. **Other:** Supporting datasets that do not fit within the preceding categories but are used to develop, calibrate, validate, or apply model results.

1. WDRM

The WDRM v4 risk data is composed and aggregated from 21 event probability models and the wildfire consequence model. Many of the event probability models use dozens of inputs from multiple source datasets. To provide additional context, the applicable model input categories used within the WDRM v4 are described below, including how those categories support the overall risk modeling methodology. Table 7-5 documents the aggregate list of contributing data sources across the WDRM composite model suite, including the source dataset name, input category, description of the input, and source of data. Additional details regarding the specific attributes used by individual models are available in the DEPM v4 and the WFC v4 model documentation.

I. **Equipment/Assets:** Equipment and asset data are used to characterize the condition, configuration, exposure, and operating environment of electric infrastructure and to estimate wildfire ignition likelihood associated with electric assets.

II. **Topography:** Topographic data used to characterize terrain features that influence asset accessibility, vegetation interactions, fire behavior, and wildfire spread potential.

III. **Weather:** Weather data used to characterize environmental conditions that influence asset failure likelihood, ignition potential, and wildfire behavior.

IV. **Vegetation:** Vegetation data are used to assess vegetation-related ignition drivers, fuel characteristics, and wildfire spread potential that contribute to wildfire risk.

V. **Climate Change/Climate Assumptions:** Not included in the WDRM v4.

VI. **Social Vulnerability**: Access and Functional Needs (AFN) are considered when assessing egress capability.

VII. **Physical Vulnerability:** Physical vulnerability data are used to quantify exposure of people and structures that may be impacted by a wildfire and therefore contribute to wildfire consequence estimation.

VIII. **Coping Capacities**: Used to estimate the potential consequences of wildfire events by accounting for factors that influence the effectiveness of wildfire response and the ability of affected populations to evacuate.

IX. **Financial:** Not included in the WDRM v4.

X. **Cost Assumptions:** Not included in the WDRM v4.

XI. **Financial Assumptions:** Not included in the WDRM v4.

XII. **Mitigation Effectiveness Datasets:** Not included in the WDRM v4.

XIII **Other:** Supporting datasets are used to calibrate, validate, and enhance wildfire ignition and consequence modeling where the data does not fit within the primary input categories above.

TABLE 7-5:
WDRM V4 CONTRIBUTING MODELS INPUTS SOURCE DATASETS

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only) [(a)]
1	AKM pole to conductor lookup	I. Assets	PG&E Asset Knowledge Management team's dataset connecting poles to conductors	N/A Internal
2	corrosion_zones, electric corrosion area	I. Assets	PG&E defined corrosion zones for electric assets.	N/A Internal
3	Cyme	I. Assets	Snapshots of the CYME 'is protected' values for primary overhead conductors	N/A Internal
4	Edtlm	I. Assets	A time-series of the transformer loading data sourced from TLM	N/A Internal
5	epss_activation_and_devices	I. Assets	EPSS device activation history, the assets each device protects, and the fraction of days each grid pixel has such protection	N/A Internal
6	FEA of line slap	I. Assets	ATS Finite Element Analysis of line slap in HFTD based on LiDAR and EDGIS data	N/A Internal
7	lidar poles	I. Assets	LiDAR captured data of distribution poles in HFTD	N/A Internal
8	lidar spans	I. Assets	LiDAR captured data of distribution conductor spans in HFTD	N/A Internal
9	Pldb	I. Assets	A snapshot of the pole loading database (PLDB)	N/A Internal
10	Ptt	I. Assets	A time-series of the pole test & treat invasive inspections	N/A Internal

TABLE 7-5:
WDRM V4 CONTRIBUTING MODELS INPUTS SOURCE DATASETS
(CONTINUED)

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only) [(a)]
11	rada notifications	I. Assets	SAP notifications and notification items combined with SAP cause and other supplemental information for asset repair tags.	N/A Internal
12	Splices	I. Assets	Combination of multiple sources of splice installations: historical splice db, pronto inspections, and inspect app inspections,	N/A Internal
13	support structure v2 snapshot	I. Assets	Ontology Level 2 dataset of distribution support structures maintained by the PG&E OIT team.	N/A Internal
14	Circuit Segment Geometry	I. Assets	Geospatial data representing the location, boundaries, length, and configuration of circuit segments within the electric distribution system.	N/A Internal
15	high_fire_threat_district	II. Topography	HFTD – produced by CPUC	www.cpuc.ca.gov/industries-and-topics/wildfires/fire-threat-maps-and-fire-safety-rulemaking
16	national_elevation_database	II. Topography	National Elevation Dataset (NED) – produced by United States Geological Survey (USGS)	https://www.usgs.gov/publications/national-elevation-dataset

TABLE 7-5:
WDRM V4 CONTRIBUTING MODELS INPUTS SOURCE DATASETS
(CONTINUED)

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only) [a]
17	Technosylva TDI	VIII. Coping Capacities	Technosylva Terrain Difficulty Index data.	N/A Internal
18	Gridmet	III. Weather	University of Idaho Gridded Surface Meteorological Dataset provides high spatial resolution (~4-km) daily surface fields of temperature, precipitation, winds, humidity and radiation across the contiguous United States.	https://developers.google.com/earth-engine/datasets/catalog/IDAHO_EPSCOR_GRIDMET
19	Nclimgrid	III. Weather	U.S. Gridded Standardized Precipitation Index from nClimGrid-Monthly.	https://www.drought.gov/data-maps-tools/us-gridded-standardized-precipitation-index-spi-nclimgrid-monthly
20	pge_meteorology	III. Weather	2023 update to the FPI model from 2021. POMMS data used as inputs to, or the outputs of, the FPI model.	N/A Internal
21	Rtma	III. Weather	The Real-Time Mesoscale Analysis is a high-spatial and temporal resolution analysis for near-surface weather conditions. This dataset includes hourly analyses at 2.5 km for the continental US. The data is produced by National Oceanic and Atmospheric Administration (NOAA) and National Weather Service (NWS).	https://registry.opendata.aws/noaa-rtma/ https://developers.google.com/earthengine/datasets/catalog/NOAA_NWS_RTMA

TABLE 7-5:
WDRM V4 CONTRIBUTING MODELS INPUTS SOURCE DATASETS
(CONTINUED)

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only) [a]
22	Bcm	IV. Vegetation	A regional water balance software package data release and model archive for hydrologic California, water years 1896-2020	https://www.sciencebase.gov/catalog/item/5f29c62d82cef313ed9edb39
23	calfire	IV. Vegetation	Tier One High Hazard Zones for Tree Mortality. Tier 1 High Hazard Zones are where tree mortality directly coincides with critical infrastructure. They pose a threat to life and property. Tier Two High Hazard Zones for Tree Mortality. Tier Two High Hazard Zones are based on watersheds and represent areas for forest health restoration and fire planning.	https://gis.data.ca.gov/maps/CALFIRE-Forestry::california-high-hazard-zones-tier-1/about
24	cwhr	IV. Vegetation	California Wildlife Habitat Relationships (CWHR) version 9.0 - produced by California Department of Fish and Wildlife.	https://wildlife.ca.gov/Data/CWHR
25	landfire_fuels	IV. Vegetation	LANDFIRE Scott and Burgan Fire Behavior Fuel Models output data, aka FBFM40, which is derived from Landsat imagery.	https://www.landfire.gov/fbfm40.php
26	landfire_surface_fuels	IV. Vegetation	LANDFIRE surface fuels model - produced by USGS. From 2016	https://landfire.gov/data/lf2016

TABLE 7-5:
WDRM V4 CONTRIBUTING MODELS INPUTS SOURCE DATASETS
(CONTINUED)

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only) [(a)]
27	national_land_cover_database	IV. Vegetation	National Land Cover Database (NLCD) – produced by USGS	https://developers.google.com/earth-engine/datasets/catalog/USGS_NLCD_RELEASES_2016_REL
28	national_terrestrial_ecosystems	IV. Vegetation	The GAP/LANDFIRE National Terrestrial Ecosystems data provides detailed vegetation and land cover classification for the U.S. The data is produced by the USGS.	https://www.sciencebase.gov/catalog/item/requestDownload/573cc51be4b0dae0d5e4b0c5?filePath=__disk__d3%2F0c%2F5d%2Fd30c5d9060449ba3d60bcc9af164f0c2d9e75d62
29	Technosylva 2030 fuels	IV. Vegetation	Technosylva 2030 fuels layer data.	N/A Internal
30	Treemap	IV. Vegetation	A tree-level model of conterminous US forests circa produced by imputation of FIA (US Forest Service Inventory and Analysis) plot data.	https://www.nature.com/articles/s41597-020-00782-x
31	vegetation_merged, vegetation_satellite	IV. Vegetation	High resolution, territory-wide vegetation data - tree heights, strike tree count and density, etc - produced by merging PG&E-collected LiDAR data and Salo Sciences-processed satellite data.	N/A Internal

TABLE 7-5:
WDRM V4 CONTRIBUTING MODELS INPUTS SOURCE DATASETS
(CONTINUED)

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only)
32	AFN	VII. Social Vulnerability	Access and Functional Need demographic data.	https://www.pge.com/assets/pge/docs/outages-and-safety/safety/psps-afn-report-04-30-2024.pdf
33	Open street map	VII. Physical Vulnerability	Geographic database that includes a buildings data set with location and structure type information.	https://www.openstreetmap.org/#map=5/38.01/-95.84
34	world_pop	VII. Physical Vulnerability	WorldPop estimates number of people residing in each 100m by 100m grid cell in PG&E service territory.	https://developers.google.com/earth-engine/datasets/catalog/WorldPop_GP_100m_pop
35	Wildfire Suppression Impact Model	VIII. Coping Capacities	A model that assesses how terrain and accessibility conditions may influence wildfire suppression effectiveness and modifies estimated wildfire impacts, including structures destroyed and associated consequences.	N/A Internal
36	Public Egress Impact Model	VIII. Coping Capacities	A model that evaluates factors associated with evacuation challenges and modifies estimated wildfire impacts by reflecting differences in the potential consequences to populations with varying access and functional needs.	N/A Internal
37	CAL FIRE Redbooks	XIV. Other	Annual publications on the outcomes of major fires that burn more than 300 acres with recorded fire outcomes of acres burned, structures destroyed, and fatalities	https://www.fire.ca.gov/our-impact/statistics

TABLE 7-5:
WDRM V4 CONTRIBUTING MODELS INPUTS SOURCE DATASETS
(CONTINUED)

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only)
38	gNATSGO	XIV. Other	The gridded National Soil Survey Geographic Database (gNATSGO) is a United States Department of Agriculture, Natural Resources Conservation Service (USDA-NRCS) Soil & Plant Science Division (SPSD) composite database that provides complete coverage of the best available soils information for all areas of the United States.	https://www.nrcs.usda.gov/wps/portal/nrcs/detail/soils/survey/geo/?cid=nrcseprd1464625
39	SED	XIV. Other	CPUC SED reports	https://www.cpuc.ca.gov/about-cpuc/divisions/safety-and-enforcement-division/sed-monthly-reports
40	Technosylva fire simulations	XIV. Other	Technosylva fire simulations at electrical asset and historical fire ignition locations.	N/A Internal
41	VIIRS	XIV. Other	NASA Visible Infrared Imaging Radiometer Suite that provides data collected by satellites that pass over the PG&E service territory every 10 to 12 hours. The satellite raw detections for time, intensity, and location are processed by Sonoma Technology Inc. into fire records organized by unique VIIRS Fire IDs.	N/A Internal
42	N/A	Climate Change	Not included in WDRM v4	N/A

(a) Websites accessed on September 16, 2026.

The above inputs support the calculation of the 21 event probability models and the Wildfire Consequence Model, which serve as the precursor calculations of the WDRM v4. These precursor calculations are aggregated to derive the WDRM KDMMs, including Ignition Likelihood, Ignition Consequence, Ignition Risk, and Overall Utility Risk (OUR). Additional details regarding the WDRM methodology, assumptions, model derivation, and the individual event probability models are provided in PG&E's response to Section 2.7.2 of the EUP Guidelines (Section D, Model Reports) and in the DEPM v4 and WFC v4 model documentation.

2. OPRM: EPSS and PSPS Risk Model Inputs

The OPRM includes inputs from both the EPSS and PSPS Risk Models. These sub-models estimate the reliability risk associated with outages caused by EPSS and PSPS programs. To provide additional context, the model input categories applicable to the EPSS and PSPS Risk Models are described below, including their role in the overall risk modeling methodology. Tables 7-6 and 7-7 below outline the source dataset name, the input category (aligned with EUP Guidelines Section 2.7.5.1), a description of the input, and the source of data.

I. **Equipment/Assets:** Equipment and asset data characterize electric system configuration, asset connectivity, network topology, and outage history and support the estimation of outage likelihood and customer exposure.

II. **Topography:** Not a direct input into the EPSS or PSPS Risk Models.

III. **Weather:** Weather data identify historical EPSS and PSPS operating conditions, characterize outage-producing environmental conditions, and support the estimation of future outage events.

IV. **Vegetation:** Not a direct input into the EPSS or PSPS Risk Models.

V. **Climate Change/Climate Assumptions:** Not included in the EPSS or PSPS Risk Models**.**

VI. **Social Vulnerability:** Used to reflect differences in outage consequences across customer populations by incorporating characteristics associated with increased vulnerability to service interruptions.

VII. **Physical Vulnerability:** Physical vulnerability data quantify the number and characteristics of customers affected by outages, including critical and vulnerable customer populations, and support the estimation of outage consequences.

VIII. **Coping Capacities:** Not included in the EPSS or PSPS Risk Models.

IX. **Input Models:** Input models provide intermediate estimates, including outage likelihood, circuit geometry, and exposure metrics, that are incorporated into downstream outage risk calculations.

X. **Financial:** Financial data are used to monetize outage consequences and estimate the economic impacts associated with customer interruptions.

XI. **Cost Assumptions:** Not included in the EPSS or PSPS Risk Models.

XII. **Financial Assumptions:** Not included in the EPSS or PSPS Risk Models.

XIII. **Mitigation Effectiveness Datasets:** Not included in the EPSS or PSPS Risk Models.

XIV. **Other:** Not included in the EPSS or PSPS Risk Models.

TABLE 7-6:
EPSS RISK MODELS INPUTS SOURCE DATASETS

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only)
1	Electric Trace Data	I. Equipment / Assets	Geospatial network model data representing grid topology, including asset connectivity, circuit structure, network configuration (e.g., overhead vs. underground), and isolation boundaries used for system tracing.	Internal PG&E
2	Asset Data from GIS	I. Equipment / Assets	Asset registry data describing the physical characteristics, classification, installation attributes, and operational status of electric system equipment and devices maintained in GIS.	Internal PG&E
3	EPSS Lookback	I. Equipment / Assets III. Weather	Historical outage data used to identify outages that occurred during EPSS-enabled periods. These outages are considered EPSS outages.	Internal PG&E
4	Customer Connection Status	VII. Physical Vulnerability	Customer service data capturing the number and types of customers associated with grid assets or zones, including criticality indicators (e.g., medical baseline, life support, Critical Facilities) and outage exposure.	Internal PG&E
5	WDRM v4	IX. Input model	Provides probability of failure and Circuit Segment geometry, which are used to estimate outage likelihood.	Internal PG&E
6	ICE 2.0 Calculator	X. Financial	Used to estimate the financial impact of EPSS outages.	https://icecalculator.com/documents
7	Outage History	I. Assets / III. Weather / VII. Physical Vulnerability	Historical outage event data capturing failure characteristics, outage duration, customer impacts, causes, and event classifications used for reliability analysis, performance evaluation, and reporting.	Internal PG&E

TABLE 7-7:
PSPS RISK MODELS INPUTS SOURCE DATASETS

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only)
1	Circuit Segment Geometry	I. Assets	Geospatial data representing the location, boundaries, length, and configuration of circuit segments within the electric distribution system.	Internal PG&E
2	PSPS Lookback	III. Weather	Based on historical weather data and past PSPS events, this input identifies Circuit Segments that have been de-energized under current PSPS criteria.	Internal PG&E
3	ICE 2.0 Calculator	X. Financial	Used to estimate the financial impact of PSPS outages.	https://icecalculator.com/documents
4	Critical Customer Data	VI. Social Vulnerability	Customer classification data identifying critical facilities, public safety partners, medically vulnerable customers, low-income customers, and other customer groups used to characterize the relative consequences of electric service interruptions.	Internal PG&E

The above inputs for the OPRM support the calculation of the precursor metrics EPSS Likelihood, EPSS Consequence, PSPS Likelihood, and PSPS Consequence. These precursor calculations are used to derive the following KDMMs: Outage Program Likelihood and Outage Program Consequence for each Circuit Segment, as well as Outage Program Risk and Overall Utility Risk. Additional details on the derivation and usage of these models are provided in PG&E's response to Section 2.7.2 of the EUP Guidelines (Section D, Model Reports) and in the model documentation for the EPSS and PSPS Risk Models.[190]

3. WBCA

A number of the key inputs into the WBCA are discussed above (WDRM and OPRM). More comprehensive details are available in the WBCA Whitepaper[191] and in Chapter 5, Section C.3. The inputs listed in Section 2.7.5.1 of the EUP Guidelines are summarized below:

I. **Equipment/Asset inputs:** WBCA does not include specific equipment/asset inputs, it relies on values from Core Risk Models (WDRM, OPRM).

II. **Topography:** WBCA does not include specific topography inputs, it relies on values from Core Risk Models.

III. **Weather:** WBCA does not include specific weather inputs, it relies on values from Core Risk Models.

IV. **Vegetation:** WBCA does not include specific vegetation inputs, it relies on values from Core Risk Models**.** However, the WBCA includes vegetation management cost assumptions.

V. **Climate Change / Climate Assumptions:** Include Fire Weather Index analysis, Heat Day analysis to inform climate multipliers over the life of the assets.

VI. **Social vulnerability:** WBCA does not include specific social vulnerability inputs, it relies on values from Core Risk Models.

VII. **Physical vulnerability:** WBCA does not include specific physical vulnerability inputs, it relies on values from Core Risk Models.

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190 Attach. B, WP018 and WP020, respectively.

191 Attach. B, WP006.

VIII. **Coping Capacities:** WBCA does not include specific coping capabilities inputs, it relies on values from Core Risk Models.

IX. **Input Models:** Not included in the WBCA Model

X. **Financial:** Not included in the WBCA Model

XI. **Cost Assumptions:** Includes capital installation costs and lifetime operations and maintenance costs. These values are based on previously approved regulatory filings and internal PG&E analyses.

XII. **Financial Assumptions:** Includes assumptions for asset life, discount rates, inflation assumptions and risk monetization values.

XIII. **Mitigation Effectiveness Datasets:** These datasets include Wildfire Mitigation Effectiveness values, Public Safety Mitigation Effectiveness values (PCEEE) and Baseline Outage Risk Mitigation Effectiveness.

The WBCA inputs support the calculation of the BCR for each Alternative Mitigation for each Circuit Segment. Additional details on the inputs, assumptions and calculations of the models are provided in the model documentation for the WBCA Whitepaper.[192]

4. Enterprise Bow Tie Model

The model input categories applicable to the Enterprise Bow Tie Models are described below. Table 7-8 shows the source dataset name, the input category, description and the source of the primary input source datasets. These inputs are used by the Enterprise Bow Tie Models to produce standardized enterprise-level outputs, including expected annual frequency, expected consequences by attribute, and risk values expressed in both risk-neutral and risk-adjusted dollars. These precursor risk values are used in WBCA BCR calculations and provide the monetized risk foundation that integrates with WDRM and OPRM outputs to derive the following KDMMs: Outage Program Risk and Overall Utility Risk (OUR).

I. **Equipment / Assets**: Not included in the Enterprise Bow Tie Models.

II. **Topography:** Not included in the Enterprise Bow Tie Models.

III. **Weather:** PSPS lookback analysis which is based on historical weather data informs the event frequency and consequence of PSPS Bow Tie Model.

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192 Attach. B, WP006.

IV. **Vegetation:** Not a direct input into the Enterprise Bow Tie Models.

V. **Climate Change / Climate Assumptions:** Wildfire baseline risk bow tie model uses projection of number of days above the 95th percentile of historical Fire Weather Index (FWI) to escalate the percentage of fires occurring during Red Flag Warning (RFW) conditions and uses the projection of heat days to escalate the ignition frequence associated with heat-driven equipment failures. PSPS and EPSS Bow Tie models do not include climate change/climate assumptions.

VI. **Social Vulnerability:** Not included in the Enterprise Bow Tie Models.

VII. **Physical Vulnerability:** Not included in the Enterprise Bow Tie Models.

VIII. **Coping Capacities:** Not included in the Enterprise Bow Tie Models.

IX. **Input Models:** Wildfire baseline risk bow tie model uses model results from WDRM v4 to rank and allocate distribution Circuit Segments into tranches. PSPS and EPSS Bow Tie models do not include Input Models.

X. **Financial:** ICE 2.0 calculator combined with PG&E specific inputs are used to estimate the Value of Service (VoS) for monetizing customer outage impact. Value of Statistical Life (VSL) per U.S. DOT guidance is used for safety monetization.

XI. **Cost Assumptions:** Not included in the Enterprise Bow Tie Models.

XII. **Financial Assumptions:** Not included in the Enterprise Bow Tie Models.

XIII. **Mitigation Effectiveness Datasets:** Not included in the Enterprise Bow Tie Models.

XIV. **Other:** Supporting datasets that do not fit within the preceding categories but are used to develop, calibrate, validate, or apply model results.

TABLE 7-8:
ENTERPRISE RISK BOW TIE MODEL INPUT SOURCE DATASETS

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only)
1	PG&E ignitions	XIV. Other	PG&E ignition investigation data on PG&E asset ignitions (location, cause, size, reportability).	Internal PG&E
2	SED Wildfire Incident Investigation Reports	XIV. Other	CPUC Safety and Enforcement Division (SED) reports on staff investigations of wildfires involved with electric investor-owned utility (IOU) equipment to assess utility compliance with applicable rules and regulations.	https://www.cpuc.ca.gov/industries-and-topics/wildfires/wildfires-staff-investigations
3	CalFire Redbooks	XIV. Other	Annual publications on the outcomes of major fires that burn more than 300 acres with recorded fire outcomes of acres burned, structures destroyed, and fatalities, which are used to calibrate severe consequence outcomes.	https://www.fire.ca.gov/our-impact/statistics
4	WDRM v4	IX. Input model	Provides mileage by HFTD/HFRA designation, frequency and risk of wildfire by Circuit Segment which are used to assigning Circuit Segments to tranches.	Internal PG&E
5	Service Point ID Count	XIV. Other	Count of active Service Point IDs (SPID) connected to OH transformers by HFTD/HFRA designation and circuit segment.	Internal PG&E
6	PSPS Damages and Hazards	XIV. Other	Post-PSPS damage and hazard observations used to estimate avoided ignitions.	Internal PG&E
7	EPSS outages	XIV. Other	EPSS outage records capturing CMI and causes to estimate avoided ignitions.	Internal PG&E
8	PG&E Fire Weather Index forecast	V. Climate Change / Climate Assumptions	Projected number of days above historical 95th percentile of Fire Weather Index for all Distribution Overhead Circuit Segments and Transmission Overhead lines.	Internal PG&E

TABLE 7-8:
ENTERPRISE RISK BOW TIE MODEL INPUT SOURCE DATASETS
(CONTINUED)

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only)
9	Climate multipliers for heat driven equipment failures	V. Climate Change / Climate Assumptions	Projected increase in heat driven equipment failures based on forecasted percentage increase in heat days by division.	Internal PG&E
10	CAIRS Data	XIV. Other	2012-2015 California All Incident Reporting System (CAIRS) Wildland Fire Incidents, used to calibrate the safety consequence of fires less than 300 acres.	California All Incident Reporting System, downloaded copy (this dataset has since discontinued)
11	CAL FIRE financial Consequences	XIV. Other	2014 - 2017 California total fire damage in dollars and fire count by county and by size bucket, used to calibrate the financial consequence of fires less than 300 acres.	Cal Fire, downloaded copy (this dataset has since discontinued)
12	PSPS Lookback	III. Weather	PSPS lookback analysis based on historical weather data provides customers de-energized and total CMI under current PSPS criteria.	Internal PG&E
13	U.S. Widespread Outage data	XIV. Other	Used to model the reliability and indirect safety consequence of PSPS events.	Various web content based on searching the event name.
14	PSPS cost data	XIV. Other	Historical PG&E PSPS cost data covering operational and customer support costs, used to calibrate the financial consequence of PSPS events.	Internal PG&E
15	Distribution overhead outage data	XIV. Other	Distribution overhead outages data logged in Integrated Logging and Information System (ILIS), which is used to model the EPSS outage frequency.	Internal PG&E

TABLE 7-8:
ENTERPRISE RISK BOW TIE MODEL INPUT SOURCE DATASETS
(CONTINUED)

Line No.	Source Dataset Name	Category	Description	URL (Sources External to PG&E Only)
16	Outage restoration cost	XIV. Other	Outage restoration cost data from emergency work orders used to calibrate the financial consequence of EPSS outages.	Internal PG&E
17	Safety incident data	XIV. Other	Serious Injuries and Fatalities from the Electric Incident Report database, used to calibrate the safety consequence of EPSS outages.	Internal PG&E
18	Value of Statistical Life	X. Financial	VSL per U.S. DOT guidance for safety monetization.[193]	https://www.transportation.gov/resources/value-of-a-statistical-life-guidance
19	Value of Service (VoS)	X. Financial	VoS from the ICE Calculator for monetizing customer outage impacts.	https://icecalculator.com/documents

193 U.S. Department of Transportation, Valuation of a Statistical Life Guidance (updated Apr. 4, 2021), available at: <https://www.transportation.gov/resources/value-of-a-statistical-life-guidance> (accessed June 4, 2026).

I. Version and Calibration Changes (EUP Guidelines Section 2.7.5.2)

The Large Electrical Corporation must describe its anticipated schedule for updating its modeling system and methods for recording these changes in a narrative section of one page or less in the EUP. The Large Electrical Corporation must establish a naming system to track historical versions and calibrations. The naming system must be described in a narrative section of one page or less in the EUP.

Version changes are qualitative updates that substantially change the way that the risk model operates and must be accompanied by a new model report (see Section 2.7.2), the establishment of a new Baseline, and a historical backtest (see Section 2.7.6).

Version changes must markedly improve the Risk Modeling Methodology. The Large Electrical Corporation must substantiate this improvement through the submission of an updated Model Report, with all the sections and requirements detailed in Section 2.7.2, as a subsection of a Progress Report at least 6 months prior to the integration of the new version into the plan.

Calibration changes are smaller changes that do not significantly impact the Model Risk Landscape and only require the establishment of a new Baseline.

Examples of qualitative updates that are large or significant enough to change the versioning of the modeling system include, but are not limited to:

a. Adding or removing any models to/from the system.

b. Replacing a model with an alternative.

c. Any update to a model which a third-party model developer employed by the Large Electrical Corporation lists as a version update.

d. Retraining an overparameterized neural network on a new dataset.

e. Applying a new optimization procedure for a non-convex problem.

f. Implementation of a new methodology to compute a Project Variable Modifier (PVM).

Examples of qualitative updates that are not significant updates to the version changes, but do qualify as calibration updates, include, but are not limited to, the following:

a. Updating an existing historical actuarial table.

b. Fixing minor code errors.

c. Cleaning input data.

d. Updating a PVM based on new data, using a process established in the application or previous Progress Report.

The Large Electrical Corporation must include information on modeling changes in a narrative section of at most two pages in the Progress Reports.

PG&E intends to update our modeling systems as follows:

- WDRM, OPRM and WBCA: Every version release in line with the WMP cycle, beginning in 2028 to align with the anticipated timing of the 2031-2034 WMP and GRC;
- Enterprise Bow Tie: Every version release typically updated to support major planning and regulatory deliverables, beginning with the 2028 RAMP for the 2031-2034 GRC.
- The methods for recording changes to the risk models are as follows.
- WDRM: Changes are presented and approved by PG&E's internal Wildfire Risk Governance Steering Committee (WRGSC);
- OPRM: Changes are presented and approved by PG&E's WRGSC;
- WBCA: Changes are presented and approved by PG&E's Undergrounding Program executive officer.

The WRGSC makes decisions regarding PG&E's efforts to prevent catastrophic wildfires, mitigate wildfire risk, and reduce customer impact related to wildfire safety measures. The scope of the WRGSC includes new risk models, including refreshed input data on existing models, or changes to risk models.

PG&E established a naming system to track historical versions and calibrations for our risk models (see chapter 8, Section C.4). PG&E will assign risk model version identifiers using a standardized naming convention to track historical model releases and calibration updates. Each model release is assigned a version number in the format **v#**, where # is a sequential, ascending integer (e.g., v1, v2, v3). Calibrations are generally performed as part of a model version release and therefore do not typically result in a separate identifier. However, if a calibration is performed independently of a model release, PG&E will assign a calibration identifier in the format c#, where # is a sequential, ascending integer representing the approved calibration.

The version and calibration identifiers are appended to the risk model name using the convention MODEL_v[#]c[#], which reflects both the applicable model version and standalone calibration status. For example, WBCA_v1c0 indicates WBCA Version 1 with no standalone calibration updates since the model release.

- **Version Changes:** For each approved model version change, PG&E will increment the version number by one and reset the calibration identifier to zero (e.g., WDRM_v4c0 to WDRM_v5c0).
- **Standalone Calibration Changes:** If a calibration is approved independently of a model version release, PG&E will increment the calibration identifier by one while maintaining the existing version number (e.g., WDRM_v5c0 to WDRM_v5c1).

The naming system PG&E will use to track historical versions and calibrations is provided in Table 7-9 below.

TABLE 7-9:
RISK MODEL NAMING SYSTEM TO TRACK HISTORICAL VERSIONS AND CALIBRATIONS

Line No.	Risk Model Name	Risk Model Version at the Time of EUP Submittal	Risk Model Version at Next Version Change	Risk Model Version at Next Standalone Calibration Change
1	WDRM	Version 4 (WDRM_v4c0)	WDRM_v5c0	WDRM_v5c1
2	OPRM	Version 1 (OPRM_v1c0)	OPRM_v2c0	OPRM_v2c1
3	WBCA	Version 1 (WBCA_v1c0)	WBCA_v2c0	WBCA_v2c1
4	Bow Tie Model	Bow Tie Model v.Oct2026_c0	Bow Tie Model v.FutureVersion_c0	Bow Tie Model v.FutureVersion_c1

Pursuant to Section 2.7.5.2 of the EUP Guidelines, PG&E will substantiate version changes by submitting a new model report, establishing a new Baseline and preparing a backtest report six months prior to the integration of a new model version into the plan. PG&E will also establish a new Baseline each time we make a calibration change to one of our risk models.

J. Model Retention and Update Schedule (EUP Guidelines Section 2.7.6)

The Large Electrical Corporation must establish model and calibration retention policies. The Large Electrical Corporation must retain models and calibrations data for the lifetime of the program.

The Large Electrical Corporation must describe its plan to update its Risk Modeling Methodology, including details regarding how and when model version and calibration updates are planned. Any new version or calibration will require a new risk_model_version_id and risk_model_calibration_id in the data submission, respectively. See Appendix C of these Guidelines for more details.

When a new model or model version is introduced to the Risk Modeling Methodology, after the approval of an EUP, the Large Electrial Corporation must submit a Model Report (as described in Sections 2.7.2 and 2.7.5.2 of these Guidelines) as a subsection of the Progress Report to Energy Safety as well as an historical backtest of the new model's impact on all KDMMs for all Baselines since the start of the EUP (Appendix C, Section C.1.5).

In each Model Report, including in Progress Report 0 and subsequent Progress Reports, the Large Electrical Corporation must establish a new Baseline which reflects the existing distribution system as detailed in Section 2.7.5 of these Guidelines.

Risk scores for new equipment/alignment must be reported in the same granularity, scale and methodology as previously existing equipment. These evaluations must be conducted in accordance with the Large Electrical Corporation's Risk Modeling Methodology, as described in the EUP, in cases where the Large Electrical corporation has not re-evaluated the risk on the new equipment.

See Chapter 8 - Model Retention and Update Schedule, Section C for details regarding PG&E's approach to establish and maintain model and calibration retention policies, update the Risk Modeling Methodology, and provide all required reports and data.

K. Project Variable Modifiers (EUP Guidelines Section 2.7.7)

A Project Variable Modifier is defined as a set of changes that are made to variables in the Risk Modeling Methodology to evaluate the effectiveness of a given Project or set of Projects and represents how the Large Electrical Corporation values the efficacy of the Alternative Mitigations. The Large Electrical Corporation must list each Project Variable Modifier, explain how the specific PVM was calculated, and explain if and how the use of a specific PVM varies in different evaluations of the Model Risk Landscape. Specifically, the Large Electrical Corporation should provide a general description summarizing what input variables to what calculations are changed, and what is the effect on the output variables and KDMMs. This information may be reported on an average-case basis.

The Large Electrical Corporation must provide a high-level description of the formal numerical processes used to arrive at the PVM. If the Large Electrical Corporation employs third-party studies to get to the PVM, it must cite the studies here. If the PVM is the result of internal studies, then the Large Electrical Corporation must describe the datasets, and detail the formal calculations. The Large Electrical Corporation must also make the third-party studies and data available to Energy Safety upon request, both during the review of the EUP and anytime during the expected lifetime of the assets installed through the EUP.

A Project Variable Modifier (PVM) is defined as a set of changes that are made to variables in the Risk Modeling Methodology to evaluate the effectiveness of a given Project or set of Projects and represent how PG&E values the efficacy of the Alternative Mitigations and Additional Comparisons.

PG&E defines PVMs as the values used in the WBCA to determine the effectiveness of a mitigation at the sub-driver level (where applicable). For example, when PG&E considers the impact that vegetation has on Wildfire Risk, we consider three vegetation sub-drivers: vegetation (branch); vegetation (trunk); and vegetation (other). The WBCA incorporates the mitigation effectiveness values for 21 sub-drivers that are then applied to each mitigation type. For example, when considering the effectiveness of mitigating wildfire impacts due to vegetation (trunk), the WBCA applies an effectiveness of approximately ~~98~~95 percent to undergrounding primary and an effectiveness of approximately ~~71~~25 percent to overhead hardening in combination with EPSS. The use of the specific PVM varies in how PG&E evaluates different mitigations at the Circuit Segment level.

A different approach applies when PG&E considers the mitigation effectiveness of alternatives against Outage Program Risk. For example, when considering the effectiveness of mitigating EPSS outage impacts, the WBCA applies an approximately 52 percent effectiveness to overhead hardening. For undergrounding primary lines, mitigation effectiveness for EPSS and PSPS risk is applied based on the extent of undergrounding, such that the undergrounded portion of a Circuit Segment is treated as fully mitigated for these Outage Program Risks. Risk reduction is applied proportionally for partially-undergrounded Circuit Segments.

The PVM values were originally calculated based on a failure mode level review. PG&E SMEs conducted this review by evaluating how successful a mitigation would be in mitigating risk resulting from specific combinations of unplanned outage events and equipment attributes (“failure modes”). PG&E’s SMEs assessed the effectiveness of each of the mitigation alternatives against more than 2,700 failure modes that occurred in our HFTD during wildfire season. The SMEs reviewed each of these failure modes, defined as an outage cause plus three additional attributes (supplemental cause, failed/involved equipment,

and equipment condition), and assigned an effectiveness rating for each mitigation at preventing an ignition from each failure mode.

PG&E provides a description and calculations for each of the PVMs, which are the mitigation effectiveness values, in our Mitigation Effectiveness Analysis (Attach B, WP001).

The EUP Guidelines require us to provide two PVM tables (Example Tables 5 and 6 in the EUP Guidelines). These tables are included in Chapter 9 and Attachment A-1 Portfolio Coversheet as Tables PCS-6 (Project Variable Modifiers Inputs) and PCS-7 (Project Variable Modifier Outputs). Table PCS-6 captures Other Notes, which point to the relevant Workpapers that describe the sub-drivers to each input.

PG&E will update the PVMs when the WBCA is updated by incorporating new outage data into the data set used to calculate sub-driver level effectiveness. This update will result in a re-weighting of the effectiveness values. Additionally, when PG&E transitions from WDRM v4 to WDRM v5, we will conduct a failure mode level review of new outages and update mitigation effectiveness values for each, based on this review.

L. Portfolio and System-Level Standards (EUP Guidelines Section 2.7.8)

The Portfolio is the set of all Confirmed Projects that have passed Screen 3. A Portfolio is a unique list of Confirmed Projects, and adding or removing Confirmed Projects from the list constitutes an update to the Portfolio and must be indicated with a new portfolio ID. The Large Electrical Corporation must update the Portfolio as Undergrounding Projects are added, removed, or changed, and report these changes through Progress Reports. All Undergrounding Projects that have passed through Screen 3 (Project Risk Analysis), and have not been abandoned, must be included in the Portfolio.

The Large Electrical Corporation must set an Ignition Risk Decrease Standard and a Reliability Increase Standard (collectively, Portfolio-Level Standards). These Portfolio-Level Standards measure the "substantial" decrease in Ignition Risk and increase in reliability per section 8388.5(d)(2) and will be used to judge the overall efficacy and efficiency of the EUP. These standards must be measured on a per-mile basis.

a. ***Ignition Risk Decrease Standard*** *is the minimum decrease in ignition-related metrics, as measured through formal calculations of the KDMMs across the entire system at both the System-Level and Portfolio-Level, that the EUP must achieve to meet the required decrease in wildfire risk.*

b. ***Reliability Increase Standard*** *is the minimum decrease in Outage Program-related metrics, as measured through formal calculations of the KDMMs across the entire system at both the System-Level and*

Portfolio-Level, that the EUP must achieve to meet the required increase in reliability.

The Large Electrical Corporation must use KDMMs that represent the minimum reduction of Ignition Risk and Outage Program Risk, across its entire electrical distribution system, on an average-case basis necessary for the EUP to be considered successful under the Plan Mitigation Objective. It is not necessary for each iteration of the Portfolio to meet each of these Portfolio-Level Standards. Comparison to the Portfolio-Level Standards represents an intermediate measurement of the anticipated progress achieved by the Portfolio as scoped at any given time (i.e., those Undergrounding Projects that have passed through Screen 3) in a manner which scales with the size of the Portfolio.

The Portfolio is the unique list of Confirmed Projects that have passed Screen 3 at any given time. All Undergrounding Projects that have passed through Screen 3 (Project Risk Analysis) and have not been abandoned must be included in the Portfolio. PG&E is required to establish a Portfolio-Level Ignition Risk Decrease Standard at both the System Level and the Portfolio Level, as well as a Portfolio-Level Reliability Increase Standard at the System Level and the Portfolio Level. These Portfolio Level Standards measure "substantial" reductions in ignition risk and increases in reliability, consistent with Public Utilities Code Section 8388.5(d)(2), and are used to evaluate the overall effectiveness and efficiency of the EUP. These standards are measured on a per-mile basis. Comparison to the Portfolio-Level Standards represents an intermediate measurement of the anticipated progress achieved by the Portfolio at any given time.

Portfolio Level Standards at the Portfolio Level and System Level are based on ignition and outage program risk reduction per overhead mile removed values established in the Plan Mitigation Objective. Each Progress Report contains an updated Portfolio. The current Portfolio will be assessed against the established standard in terms of Ignition and Outage Program Risk reduction achieved.

The Portfolio Level Standards at the Portfolio Level are determined based on the following methodology using the established KDMMs of Ignition Risk and Outage Program Risk:

1) **The Ignition Risk Decrease Standard at the Portfolio Level** is determined by dividing the total wildfire risk reduction used in the Plan

Mitigation Objective calculation by the total overhead miles removed in the calculation:

$$\underline{\boldsymbol{Ignition\ Decrease\ Standard\ at\ Portfolio-Level}}$$

$$\textbf{FORMULA}: \$\mathbf{0.045}\boldsymbol{M} = \frac{\$183M\ wildfire\ risk\ reduced}{4000\ OH\ Miles\ removed}$$

2) **The Reliability Increase Standard at the Portfolio Level** is determined by dividing the total outage program risk reduction used in the Plan Mitigation Objective calculation by the total overhead miles removed in the calculation:

$$\underline{\boldsymbol{Reliability\ Increase\ Standard\ at\ Portfolio-Level}}$$

$$\textbf{FORMULA}: \$\mathbf{0.100}\boldsymbol{M} = \frac{\$398M\ outage\ risk\ reduced}{4000\ OH\ Miles\ removed}$$

The Portfolio Level Standards at the System Level are determined based on the following methodology:

1) **The Ignition Decrease Standard at the System Level** is determined by dividing the total wildfire risk reduction used in the Plan Mitigation Objective calculation by the total overhead miles on the system:

$$\underline{\boldsymbol{Ignition\ Decrease\ Standard\ at\ System-Level}}$$

$$\textbf{FORMULA}: \$\mathbf{0.0023}\boldsymbol{M} = \frac{\$183M\ ignition\ risk\ reduced}{80{,}632\ system\ overhead\ miles}$$

2) **The Reliability Increase Standard at the System Level** is determined by dividing the total outage program risk reduction used in the Plan Mitigation Objective calculation by the total overhead miles on the system:

$$\underline{\boldsymbol{Reliability\ Increase\ Standard\ at\ System-Level}}$$

$$\textbf{FORMULA:}\ \$\mathbf{0.0049}\boldsymbol{M} = \frac{\$398M\ outage\ risk\ reduced}{80{,}632\ \ system\ overhead\ miles}$$

See also Table PCS-2 Portfolio Standards in Chapter 9 which provides PG&E's Risk Decrease Standards and Reliability Increase Standards that will be reported in the Portfolio Coversheet.

M. Project-Level Thresholds and Standards (EUP Guidelines Section 2.7.9)

1. Project-Level Thresholds (EUP Guidelines Section 2.7.9.1)

The Large Electrical Corporation must set and explain a High-Risk Threshold, Ignition Tail Risk Threshold, and High Frequency Outage Program Threshold (collectively, Project-Level Thresholds), using a combination of the KDMMs to establish the need for mitigation on a Circuit Segment. These Project-Level Thresholds 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.

a. ***High-Risk Threshold*** *is the Overall Utility Risk level above which a Circuit Segment is considered eligible for examination for expedited undergrounding. The High-Risk Threshold must utilize normalized units, such as risk per mile, to account for the differing lengths of Circuit Segments. The Large Electrical Corporation must provide an explanation of the metric used for normalization and an explanation of why that metric was chosen.*

b. ***Ignition Tail Risk Threshold*** *is the measure of consequence above which a Circuit Segment is considered to have significant potential for ignition of a catastrophic wildfire, so that it merits special consideration. This threshold must represent less than 1% of Circuit Segments in the entire system by mile and no more than 10% of the Ignition Consequence by score.*

c. ***High Frequency Outage Program Threshold*** *is the measure of likelihood above which a Circuit Segment is considered to have a significantly high likelihood of frequent or prolonged disruption of service to customers. This threshold must measure both likelihood of an Outage Program Event and its anticipated length. This threshold must represent less than 1% of Circuit Segments in the entire system by mile and no more than 10% of Outage Program Likelihood by score.*

a. High-Risk Threshold

PG&E established a High-Risk Threshold by determining an acceptable level of Overall Utility Risk represented as a dollar per mile threshold based on the monetized value of the Overall Utility Risk KDMM on our distribution system. The total risk of the Circuit Segment is used to determine if a Circuit Segment meets a Project-Level Threshold. Subprojects do not affect the eligibility of a Circuit Segment via Screen 1 Thresholds. Any Circuit Segment that exceeds this threshold, including Circuit Segments in Fire Rebuild Areas, should be considered for mitigation. The Pre-Wildfire distribution infrastructure

and associated risk is used as the comparison Baseline for Fire Rebuild Projects to be constructed as part of the EUP.[194]

PG&E uses the full Overall Utility Risk for a Circuit Segment and allocates that value by the HFRA/HFTD portion of the Circuit Segment. The vast majority of risk on a Circuit Segment that crosses HFTD/HFRA areas and non HFTD/HFRA areas is concentrated in HFRA/HFTD areas. PG&E uses the full Overall Utility Risk and divides by the HFRA/HFTD mileage to most accurately report the risk density due to risk model limitations. For Fire Rebuild Circuit Segments located outside the HFRA/HFTD, PG&E normalizes benefit and cost values using the full Circuit Segment length, rather than HFRA/HFTD mileage, consistent with the Circuit Segment length values (data field circuit_segment_length) reported in Table C.6.

PG&E developed loss exceedance curves for each Circuit Segment in our service territory, considering the likelihood of safety incidents (fatalities) on each Circuit Segment. A loss exceedance curve represents the annual frequency of events that exceed a specific loss level. Loss exceedance curves are used to help assess and manage potential risks. The exceedance curves are aggregated to form an exceedance curve at the HFTD/HFRA level.

PG&E evaluated industry benchmarks to determine acceptable risk. We reviewed data from the Federal Energy Regulatory Commission, the Department of Defense, the Nuclear Regulatory Commission, and the United Kingdom's Health and Safety Executive. We chose an individual risk acceptance of 0.5 x 10-6 fatalities per year defined as an acceptable risk for an average individual in the vicinity of a nuclear power plant.[195]

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194 The Pre-Wildfire distribution infrastructure for Fire Rebuild Projects where the fire occurred before January 1, 2023 would not be available for baseline comparisons. See discussion of previously-scoped projects in Chapter 3, Section D.5.

195 10 CFR Part 50, Safety Goals for Operations of Nuclear Power Plants, p. 2, ¶ 2 for the reference to average individual risk, available at: <https://www.nrc.gov/reading-rm/doc-collections/commission/policy/51fr30028.pdf> (accessed May 13, 2026). The 0.5x10-6 fatalities per year is calculated as 0.1/100 x US prompt fatality risk (varies year-to-year but was set to 5x10-4 fatalities per year as an average value using data from the Center for Disease Control and Prevention, available at: <https://wonder.cdc.gov/deaths-by-underlying-cause.html> (accessed May 13, 2026).

The individual risk acceptance criterion was converted to an acceptance loss exceedance curve, which was then used to identify the minimum number of Circuit Segments that are required for mitigation at the system level, if they were prioritized by wildfire risk per mile, to reach an acceptable level of risk in the HFTD/HFRA (in aggregate).

PG&E then draws a risk buy-down curve plotting each Circuit Segment, with overall utility risk per mile on the y-axis and wildfire risk per mile rank on the x-axis. The High-Risk Threshold is then set to the lowest Overall Utility Risk value per mile within the number of Circuit Segments that are required for mitigation. This analysis identified approximately 791 Circuit Segments above the risk acceptance criterion. The lowest Overall Utility Risk value of these 791 Circuit Segments was $28,979 per mile, which therefore serves as the High Risk Threshold. Applying this threshold value to PG&E's entire HFTD, results in 2,917 eligible Circuit Segments. Circuit Segments with an Overall Utility Risk of less than $28,979 are ineligible for the EUP under the High-Risk Threshold.

b. Ignition Tail Risk Threshold

To establish this Threshold, PG&E evaluated Circuit Segment level ignition consequence data to understand which Circuit Segments had the most significant potential for igniting a catastrophic wildfire. We sorted the Circuit Segments by the Ignition Consequence KDMM and identified those where the cumulative primary overhead mileage equaled less than one percent of the total system mileage. We established the Ignition Tail Risk Threshold as required by the EUP Guidelines by including Circuit Segments that equal less than one percent of the total system mileage and no more than 10 percent of the Ignition Consequence by score. (See EUP Guidelines Section 2.7.9.1 b.) The resulting threshold is $52.437 million per ignition, corresponding to the Circuit Segment at the one percent cumulative mileage cutoff. This is the minimum Ignition Consequence value for Projects that meet the Ignition Tail Risk Threshold. Any Circuit Segment that exceeds this threshold, including

Circuit Segments in Fire Rebuild Areas, should be considered for mitigation.

c. High Frequency Outage Program Threshold

To establish this threshold, PG&E evaluated Circuit Segment-level outage likelihood to identify those with the greatest potential for EPSS or PSPS outage impacts. PG&E sorted Circuit Segments from highest to lowest by the Outage Likelihood KDMM and identified the segment immediately before the one percent cumulative system mileage cutoff. PG&E established the threshold based on this Circuit Segment. The resulting High Frequency Outage Program Threshold is 5,559 outage minutes per year, based on the Outage Likelihood KDMM value for the Circuit Segment at the one percent cumulative mileage cutoff (see EUP Guidelines Section 2.7.9.1 b). Any Circuit Segment that exceeds this threshold, including Circuit Segments in Fire Rebuild Areas, should be considered for mitigation.

2. Project-Level Standards (EUP Guidelines Section 2.7.9.2)

The Large Electrical Corporation must set and explain Project-Level Standards, using a combination of the KDMMs, to determine the necessary level of risk reduction needed for an Undergrounding Project to be considered to merit inclusion without considering other EUP Projects. These Project-Level Standards are measured against the Baseline in place at the time the Undergrounding Project completes Screen 3. 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.

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 (see Appendix C.1.12).

The proposed Project-Level Standards, when considered in the context of the EUP and risk landscape, must ensure the EUP substantially increases electrical reliability by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs, and substantially reduces the risk of wildfire.

*a. **High-Risk Project-Level Standard** is the minimum decrease in Ignition Risk and Outage Program Risk, that an Undergrounding Project must achieve to support the Plan Mitigation Objective. This reduction in wildfire risk and*

increase in reliability must, at minimum, reduce the risk of the Circuit Segment to below the High-Risk Threshold.

b. ***High Frequency Outage Program Project-Level Standard*** *is the minimum decrease in Outage Program Likelihood as measured through formal calculations of the KDMMs that any Undergrounding Project considered under the High Frequency Outage Program must achieve to meet the required substantial increase in electrical reliability achieved by reducing the use of public safety power shutoffs, enhanced powerline safety settings, deenergization events, and any other outage programs.*

c. ***Tail Risk Project-Level Standard*** *is the minimum decrease in wildfire likelihood that any Undergrounding Project considered under the Ignition Tail Risk Threshold must achieve to meet the required substantial reduction of the risk of wildfire.*

PG&E established Project-Level Standards using a combination of the KDMMs to determine the necessary level of risk reduction needed for an Undergrounding Project to be considered to merit inclusion in the EUP without considering other EUP Projects. We measure the Project-Level Standards against the Baseline in place at the time the Undergrounding Project completes Screen 3. The Project-Level Standards ensure the EUP substantially increases reliability and reduces Wildfire Risk. The Project-Level Standards are fixed when the EUP is approved. Any Project that does not meet a Project-Level Standard is further justified in a narrative submission in Table C.12 in the "additional justification" field. The three Project-Level Standards are described below.

a. High-Risk Project-Level Standard

The High-Risk Project-Level Standard is the amount of Overall Utility Risk which a Project needs to reduce to bring the Overall Utility Risk on that Circuit Segment below the High-Risk Threshold ($28,979 per mile).

Because Circuit Segments with an Overall Utility Risk (OUR) per mile exceeding the High-Risk Threshold are classified as high-risk and therefore eligible for EUP undergrounding, while Circuit Segments below the threshold are not, the High-Risk Threshold serves as the fundamental benchmark for distinguishing high-risk conditions within the EUP's risk-based prioritization framework. As a result, it is reasonable to use this same threshold to evaluate project-level success. Reducing a

Circuit Segment's remaining Overall Utility Risk per mile below the High-Risk Threshold demonstrates that the Project has lowered risk to a level that is no longer considered high-risk under the EUP framework. Accordingly, achieving a residual Overall Utility Risk per mile below the High-Risk Threshold represents sufficient risk reduction for a high-risk project and serves as an appropriate metric for the High-Risk Project-Level Standard.

PG&E calculates the mitigation effectiveness of each system hardening mitigation type applied to each Circuit Segment. We estimate the amount of risk we will reduce on a Circuit Segment to determine if it will meet the High-Risk Project-Level Standard. We report this information in the Screen 3 Table (Table C.12). If we estimate that our proposed mitigations will not reduce enough risk to meet the High-Risk Project-Level Standard, we provide additional justification for the Project in Table C.12.

After undergrounding on a Circuit Segment is complete, PG&E calculates the amount of risk reduced by calculating the effectiveness of each mitigation applied to a Circuit Segment. We then compare the remaining risk to the High-Risk Threshold to determine if we have reduced enough risk on a Circuit Segment to bring it below the High-Risk Threshold and consider it a mitigated Circuit Segment.

b. High Frequency Outage Program Project-Level Standard

This Project Standard measures the decrease. in outage program likelihood that a Project must achieve to demonstrate substantial increase in electric reliability. Under this Standard, a Project must reduce the likelihood of EPSS and PSPS on a Circuit Segment by at least 90 percent.

While neither statute nor the EUP Guidelines prescribe a numerical threshold for what constitutes a “substantial” reduction, PG&E selected 90 percent as a conservative Standard to distinguish substantial mitigation from incremental improvement. Under this Standard, a Project must reduce at least 90 percent of pre-mitigation Ignition Likelihood or Outage Program Likelihood, leaving no more than 10 percent of the original likelihood remaining. PG&E considers this

level of reduction a readily verifiable demonstration of substantial improvement because it requires the Project to materially reduce the underlying hazard, rather than merely produce a marginal or measurable change.

PG&E assumes that undergrounding reduces the likelihood of both EPSS and PSPS events. Overhead Hardening only reduces the likelihood of EPSS; it does not reduce the likelihood of PSPS because overhead lines must be deenergized due to high winds in PSPS events.

PG&E estimates the reduction in likelihood of an outage event from a system hardening mitigation by applying the mitigation effectiveness for each system hardening type to the applicable portion of the Circuit Segment. We report this information in Table C.12 of the Progress Report. If we estimate that our proposed mitigations are insufficient to meet the High Frequency Outage Program Project-Level Standard, we provide additional explanation for the Project in Table C.12.

PG&E also reviews the reduced Outage Program Likelihood to determine if the Circuit Segment is mitigated by comparing the remaining Outage Program Likelihood value to the Standard.

c. Tail Risk Project-Level Standard

This Standard measures the decrease in Ignition Likelihood that a Project must achieve to demonstrate substantial Wildfire Risk reduction. Under this Standard, a Project must reduce Ignition Likelihood on a Circuit Segment by at least 90 percent. PG&E uses expected ignitions as the measure of Ignition Likelihood, where a reduction in expected ignitions equates to a reduction in Ignition Likelihood.

While neither statute nor the EUP Guidelines prescribe a numerical threshold for what constitutes a “substantial” Wildfire Risk reduction, PG&E selected 90 percent as a conservative Standard to distinguish substantial mitigation from incremental improvement. Under this Standard, a Project must reduce at least 90 percent of pre-mitigation Ignition Likelihood, leaving no more than 10 percent of the original likelihood remaining. PG&E considers this level of reduction a readily verifiable demonstration of substantial Wildfire Risk reduction because it requires the Project to materially reduce the underlying ignition

likelihood, rather than merely produce a marginal or measurable change.

PG&E estimates how much we will reduce the likelihood of an ignition by mitigating a Circuit Segment through undergrounding, overhead hardening, remote grid or a combination of mitigations by applying the mitigation effectiveness for each system hardening type to the portion of the Circuit Segment to which it will be applied. We will report this information in Progress Report Table C.12, including an additional justification for any Project that does not meet this Standard.

PG&E reviews the reduced Ignition Likelihood to determine if the Circuit Segment is considered a mitigated Circuit Segment by comparing the remaining Ignition Likelihood to the Tail Risk Threshold.

N. Comparative Metrics (EUP Guidelines Section 2.7.10)

For each Undergrounding Project, the Large Electrical Corporation must compare its Project to the required design variations outlined below, including an evaluation of at least two combinations of comparable Alternative Mitigations in Screen 2, and one combination of comparable Alternative Mitigations in Screen 3.

Further information on these required comparisons can be found in Section C.1.11 (Screen 2 Table), Section C.1.12 (Screen 3 Table), Section C.1.13 (Screen 4 Table) and Section C.1.15 (Project Index Table) of Appendix C.

For the purpose of comparisons in this section, the Undergrounding Project is considered to be a 100% undergrounded Circuit Segment in Screen 2. After the Project scoping phase in Screen 3, the Project must be analyzed both as the Project as Scoped (see Required Design Variations below) which includes all of the Undergrounding and non-undergrounding Subprojects and the Undergrounding as Scoped (see Required Design Variations below). If the Undergrounding Project will be a completely undergrounded Circuit Segment, the Project as Scoped, and Undergrounding as Scoped design variations will have identical information but must be included for completeness of the data submission in Screen 3 and Screen 4.

In Screen 4, the costs, benefits, and CPUC CBR must be calculated for the Project as Scoped, Undergrounding as Scoped, and the Screen 3 Alternative Mitigations. Appendix C.1.13, Screen 4 Table, gives further instructions on the requirements of Screen 4.

Design Variations Required for Comparison:

a. ***100% Undergrounded:*** *A completely undergrounded Circuit Segment must be included as a design variation in Screen 2. In Screen 3, this design variation will be replaced with Project as Scoped.*

b. ***Project as Scoped:*** *This design variation must include all work in the final Project design, including all Undergrounding and non-undergrounding*

Subprojects. This design variation must be used to justify the Project-Level Standard.

c. ***Undergrounding as Scoped:*** *This design variation must include only the portion of the Circuit Segment that is to be undergrounded (e.g. just the Undergrounding Subproject(s) without any of the non-undergrounding Subprojects). This design variation must be used to justify the Portfolio-Level Standards, Plan Mitigation Objective, and Plan Tracking Objective. If the Circuit Segment will not contain multiple mitigations, this design variation will be identical to Project as Scoped.*

d. ***Project Baseline:*** *For Screen 3 only, the existing Circuit Segment must be analyzed for the comparison of the Undergrounding Project. For Circuit Segments in Wildfire Rebuild Areas, the Pre-Wildfire distribution system and associated risk must be used for the Project Baseline.*

e. ***Screen 2 Alternative Mitigation 1****: This design variation must consist of aboveground hardening including installation of covered conductor on the entire Circuit Segment and some type(s) of protective equipment and device settings used to reduce wildfire ignition. The protective equipment and device settings must include protection hardware capable of fast trip and/or sensitive trip settings and modified recloser settings that can be enabled or disabled as needed based on changing conditions in the Tier 2 or 3 HFTD. Additionally, the Large Electrical Corporation must include any additional protection systems and settings that can enhance the safety of the Circuit Segment, as deemed feasible by the Large Electrical Corporation for each Project. These may include, but are not limited to, early fault detection, falling conductor protection, high impedance fault protection, rapid earth fault current limiter (REFCL), and partial voltage detection. Examples of existing qualifying programs include Enhanced Powerline Safety Settings (EPSS), Fast Curve Settings Sensitive Relay Profile (SRP), and Advanced Protection Program. All other applicable aboveground line hardening measures utilized by the Large Electrical Corporation must be included in this design variation unless specific Project constraints prevent it.*

f. ***Screen 2 Alternative Mitigation 2****: This design variation must include one additional mitigation or combination of mitigations that meet or exceed the risk reduction of Alternative Mitigation 1. This can include mitigation strategies currently in use by the Large Electrical Corporation or other new and proven technologies that could be reasonably implemented. For example, rapid earth fault current limiter (REFCL), line removal with remote grid, or advanced grid monitoring. The mitigations used in Alternative Mitigation 1 may be included in the combination of mitigations chosen for Alternative Mitigation 2.*

g. ***Screen 3 Alternative Mitigations****: The Alternative Mitigations used in Screen 3 and Screen 4 will be derived from the results of the Screen 2 comparison, and any new information obtained from initial Project scoping. The Screen 3 Alternative Mitigations must, at a minimum, include aboveground line hardening, covered conductor and some type of protective equipment and device settings for any line not removed, as in Screen 2 Alternative Mitigation 1. The Large Electrical Corporation must also include*

any other mitigation or combination of mitigations that it has determined would be well-suited for the specific project location.

Additional Design Variations:

- ***Additional Design Variations:*** *The Large Electrical Corporation may include additional design variations for any other combination of alternative mitigations that it wishes to report. Any unique combination of Alternative Mitigations that meet the Project-Level Standards and could be reasonably implemented by the Large Electrical Corporation should be included.*

In every design variation listed above, only the feasible work should be included. For example, if the Circuit Segment contains a large river crossing, boring under the river should not be included in the design of a fully undergrounded Circuit Segment if its cost is prohibitively high relative to the rest of the Project. Instead, a more feasible design must be used, such as an over river crossing, or the use of bridge conduit if available.

In addition to the EUP narratives required in Sections 2.4.4 and 2.4.5, each Progress Report must include a narrative detailing the Large Electrical Corporation's ongoing review of possible Alternative Mitigations. The narrative should detail what mitigations were considered since the last Progress Report, and what factors lead to the continued use of, or change in, the Alternative Mitigations used in the EUP's Project Acceptance Framework. The narrative must also include details on any relevant new and emerging technologies, and how the Large Electrical Corporation is including these technologies in its EUP. For example, the narrative must include updates on any applicable ongoing pilot programs, such as Rapid Earth Fault Current Limiters (REFCL), and details on what Portfolio-Level analysis was done to evaluate the potential benefits of implementation.

PG&E compares each Undergrounding Project to the required design variations, including at least two Alternative Mitigations in Screen 2 and one Alternative Mitigation in Screen 3. For the purpose of comparisons, the Undergrounding Project is considered to be a 100 percent undergrounded Circuit Segment in Screen 2 and the Project is analyzed both as the Project as Scoped and the Undergrounding as Scoped in Screen 3. If the Undergrounding Project will be completely undergrounded, the Undergrounding as Scoped and Project as Scope are the same, but both are included for completeness of the data submission in Screen 3 and Screen 4.

The Project as Scoped (including non-undergrounding elements) is used to justify the Project-Level Standard. However, since only the Undergrounding Subprojects are directly relevant to the EUP, the Undergrounding as Scoped is used to justify the Portfolio-Level Standards, Plan Mitigation Objective, and Plan Tracking Objective.

PG&E's EUP and Progress Report will comply with requirements of the EUP Guidelines Section 2.7.10 subsections a-g regarding the required design variations.

PG&E describes our procedures for conducting the required design variation comparisons at Screen 2 in Chapter 3, Section D.2 and at Screen 3 in Chapter 3, Section D.3.

PG&E provides information about the required design variation comparisons in Progress Report 0, specifically: (1) Screen 2 Table (C.11); (2) Screen 3 Table (C.12); (3) Screen 4 Table (C.13); and (4) Project Index Table (C.15). PG&E will provide a narrative with our Progress Report(s) about Alternative Mitigations considerations in the Portfolio Coversheet provided with each Progress Report. (See Chapter 9, Table PCS-2.)

O. PG&E's Response to SPD's Evaluation of its 2024 RAMP Regarding Modeling of Wildfire Risk

PG&E submitted our 2024 RAMP Report on May 15, 2024, in advance of our Test Year 2027 GRC. On November 8, 2024, the SPD released its Evaluation of PG&E's 2024 RAMP Report A.24-05-008 (RAMP Evaluation Report) that included observations and recommendations about each of the risks included in PG&E's RAMP. PG&E is required to address the issues raised by SPD in its RAMP Evaluation Report in the GRC. Certain of SPD's comments in the section on Wildfire Risk with PSPS and EPSS relate to selecting Undergrounding Projects and, because PG&E is only forecasting costs for undergrounding for one year (2027) in our 2027 GRC, these comments are best addressed in this EUP.

Table 7-10 below lists issues raised by SPD and intervenors in the RAMP Evaluation Report, PG&E's response, and the location in the EUP where the issue is more fully addressed.

TABLE 7-10:
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
1	Summary of Findings No. 4(b) and 4(c)	Most wildfire workpapers, especially those allocated to system hardening, lack consistency and cohesion. Specific examples include: (a) PG&E doesn't clearly outline the process for assigning risk-based tranches to specific circuit segments. There is no correlation between risk/mile and PG&E's assigned tranches. (b) No explanation of the criteria or methodology PG&E used to select miles planned for undergrounding is provided. (c) PG&E doesn't explain how the circuit segments were chosen for undergrounding.	a. See A.25-05-009, Exh. PG&E-2, WP 1-01, line 108. b. PG&E's system hardening approach generally aligns with the procedures for selecting mitigation alternatives outlined in the EUP Guidelines that were adopted February 20, 2025 (EUP Guidelines). PG&E identifies high risk circuit segments to be included in its system hardening program. PG&E selects a primary mitigation for each circuit segment (overhead hardening or undergrounding) based on the results of economic analyses. See Exh. (PG&E-4), Ch. 7, Section B (2) for additional detail in the 2027 GRC testimony. c. See response to part (b) above.	See Chapter 3 Section C for details of the Project Acceptance Framework used to select Undergrounding Projects.

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
2	Summary of Findings No. 24	The PG&E workpapers provide system hardening mitigation risk reduction, capital expenditures (CapEx), and BCRs for both program and tranche levels. However, PG&E does not clearly explain how these values have been calculated from more granular data like circuit segments, nor the underlying data supporting these calculations.	Tranche level BCRs were provided in RAMP Workpaper RM-RMC-15. PG&E will calculate BCRs at the circuit segment level for both undergrounding and overhead hardening for circuit segments that are considered for system hardening in the EUP using our WBCA model. The WBCA documentation will describe the assumptions and provides the support data for the mitigation risk reduction values and capital expenditures that are used in the BCR calculations.	See Chapter 5, Section C. 3, Chapter 7 Section D.6, and Attach B. WP006 for details of the BCR calculations.
3	Summary of Findings No. 39	PG&E did not provide SPD requested costs, risk reduction, and BCR data at the circuit segment level for all circuits proposed for undergrounding. PG&E stated, "we did not calculate NPV costs at the circuit segment level, as the capital cost per mile was a simple average across the 2027-2030 period, and	a. PG&E disagrees that the NPV risk reduction and NPV costs are inaccurate for the wildfire tranches. The enterprise risk model is a representation of the risk. Each tranche is a collection of circuit segments. BCRs can be calculated at the tranche or circuit segment level	a. See Progress Report 0, Appendix A for Screen 2 table of BCR values. b. See Progress Report 0, Table C.13 for details of the UG as Scoped costs and BCR value c. See Chapter 3 Section C for details of the Project Acceptance

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
3 (cont)	Summary of Findings No. 39 (cont.)	not a reflection of the year(s) of installation … because NPV risk reduction and NPV Costs are not calculated …the associated BCR cannot be calculated using that data." a. Considering that PG&E's risk tranches comprise numerous circuit segments, SPD finds that if PG&E did not calculate NPV costs and BCR at the circuit segment level, its NPV costs and BCR calculations for each wildfire tranche may not be accurate. b. PG&E's decision to use a simple average for capital cost per mile across the 2027-2030 period rather than reflecting the specific year(s) of installation raises concerns about the accuracy of its cost projections. The timing of capital expenditures is crucial when calculating NPV, as costs incurred earlier in the period should be discounted differently than those incurred later. Without this granularity, the NPV could be distorted, leading	independently. BCRs will be provided at the circuit segment level in the EUP. b. When PG&E transitions to the EUP it will calculate a BCR for each confirmed EUP undergrounding Project. PG&E will calculate a BCR when the circuit segment is first selected for the EUP and then will update it when the final Project scope is determined. Updating the BCR to reflect the final Project scope consists of updating cost and mileage assumptions used to calculate the BCR. The estimated costs used for calculating the updated BCR account for issues (e.g. constructability, permitting) that could impact Project costs. c. As described in part (b) PG&E will calculate BCRs at the circuit segment level when it begins its 10-year EUP. A central element of the EUP is using quantitative data such as BCRs to prioritize system hardening where they	Framework used to select Undergrounding Projects. d. See Progress Report 0, Appendix A-2 Table C.11 for Screen 2 table of BCR values.

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
3 (cont)	Summary of Findings No. 39 (cont.)	to inaccurate representations of the true costs of each circuit segment. c. PG&E asserts that it cannot calculate the BCR at the circuit segment level due to the lack of NPV risk reduction and cost data. Without BCRs calculated for individual circuit segments, PG&E cannot fully evaluate the cost efficiency of each specific Project. This could result in the misallocation of resources, potentially leading to underestimating or overestimating the risk-reduction benefits across different segments. This lack of granularity undermines PG&E's ability to prioritize wildfire mitigation efforts where they are needed most.	are needed most and to select the most appropriate mitigation for that location. d. In the EUP PG&E will provide detailed quantitative data about every circuit segment considered for system hardening that will show Energy Safety, other regulators, and stakeholders how it compared mitigation strategies and prioritized certain circuit segments based on cost efficiency, ignition risk reduction, and improvements in reliability.	

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
3 (cont)	Summary of Findings No. 39 (cont.)	d. The lack of detailed BCR data hinders SPD's ability to compare different mitigation strategies and prioritize segments based on cost efficiency. The lack of circuit-level data makes it difficult to assess and validate PG&E's mitigation proposals properly. SPD relies on detailed data to evaluate each Project's effectiveness and cost-efficiency; without it, the ability to recommend improvements or alternative strategies is limited.		
4	Summary of Findings No. 42	SPD finds that PG&E did not provide justifications for the chosen mitigations at the circuit segment level due to the timing of Project scoping.	PG&E will provide justifications for the chosen mitigation at the circuit segment level for Projects in its EUP. Circuit segment information will also be available for circuit segments not selected for the EUP.	PG&E will follow the Project Prioritization and Decision Tree in Attach. B. Workpaper 003 Project Prioritization and Decision Tree (WP003). Justification for Project selections is outlined in the decision tree.

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
5	Summary of Findings No. 43	SPD finds that PG&E partially responded to SPD's data requests related to circuit segment risk model data. However, PG&E failed to explain how changes in calculated risk across risk model versions would affect its mitigation strategy.	PG&E will address how changes in risk model versions will impact its system hardening strategy (e.g., choosing between overhead hardening and undergrounding) in its EUP. PG&E will calibrate its risk model system baseline annually during the EUP period to ensure that the risk modeling methodology is evaluated with up-to-date information that accurately reflects PG&E's understanding of risk on its system. When a new model or model version is introduced after approval of the EUP, PG&E will submit a risk model report describing the risk model methodology and calculations and will submit an historical backtest of the new model's impact on ignition risk and outage risk since the start of the EUP.	See Chapter 8 Section C for details of PG&E's risk model versioning and calibration approach.

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
6	Summary of Findings No. 44	SPD finds that changes for each circuit segment should be traceable between risk model versions to ensure proper oversight of all proposed mitigations.	In the EUP PG&E will identify which risk model version was used to select each Project considered for the EUP (Table C.10 - Project Table). Additionally, PG&E reports the risk model used to select undergrounding Projects in its annual System Hardening Accountability Report (see PG&E's 2024 SHAR, July 1, 2024, Advice Letter 7312_E, Attachment B, Field Name "Applicable Risk Model").	See Progress Report 0 Table C.10 which identifies the risk model version used to select each Project.
7	Recommended Solution No. 18	PG&E provide BCR calculations for undergrounding, covered conductor and operational mitigations for each tranche and circuit segment for which it proposes investments to mitigate wildfire risks.	PG&E will calculate BCRs for all circuit segments considered for system hardening in its EUP. BCRs will be calculated for undergrounding, overhead hardening, Hybrid Projects (a combination of undergrounding and overhead hardening on a single circuit segment).	See Progress Report 0, Table C. 11 for Screen 2 table including BCR values.

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
8	Recommended Solution No. 22	PG&E investigate the feasibility and provide related information for various mitigations, undergrounding (UG), covered conductor (CC), CC+REFCL, CC+EPSS, and EPSS-solely mitigations, and any other proposed mitigations, for each circuit segment.	In the EUP, PG&E will provide information about undergrounding, overhead hardening and Hybrid Projects (circuit segments with both undergrounding and overhead hardening on the same circuit segment) for each circuit segment as required by the EUP Guidelines (Section 2.7.10). PG&E is not required to provide information about other mitigation combinations at the circuit segment level in the EUP. PG&E does estimate the effectiveness of mitigation combinations (e.g. covered conductor + EPSS) in the HFTD.	PG&E has included feasible mitigation alternatives in the Screen 2 and Screen 3 assessments outlined in Chapter 3.
9	Informal Intervenor Comments of the Public Advocates Office, p. 8	PG&E should calculate the cost-benefit ratios (CBR) of its undergrounding program as both a safety mitigation and a reliability mitigation.	Calculating BCRs for the undergrounding program as both a safety mitigation and a reliability mitigation is not a requirement in the GRC. In the EUP, PG&E will consider the risk tradeoffs between wildfire and operational mitigations in its BCR calculation.	See Chapter 3 Section C for details of the Project Acceptance Framework including the Alternative Mitigations considered. See Chapter 5 for details of the WBCA calculation methodology.

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
9 (cont)	Informal Intervenor Comments of the Public Advocates Office, p. 8 (cont.)		The BCR calculation PG&E will use for the EUP will consider PSPS as part of the risk baseline and will include EPSS as part of the covered conductor mitigation.	
10	Informal Intervenor Comments of the Mussey Grade Road Alliance (MGRA), p. 32	PG&E should be required in the GRC to include covered conductor and DCD as one of its alternative mitigations. MGRA requested that PG&E provide an analysis of covered conductor only for RAMP and it has done so in DR Response RAMP-2024_DR_MGRA_001_Q011 .	PG&E is not required to provide alternative mitigation analyses in its GRC. PG&E will consider alternative mitigations and present alternative mitigation analyses in its EUP.	See Chapter 3 for the alternatives considered at each phase of the Project Acceptance Framework. Covered Conductor is considered Alternative 1 for Screens 2 and Screen 3 Alternative Mitigation for Screen 3.
11	Informal Intervenor Comments of MGRA, p. 36	PG&E should provide updated analysis of alternative mitigations along as part of its GRC application that include scenarios: (1) including covered conductor and DCD/EPSS, (2) assuming higher wildfire mitigation efficiency for covered conductor consistent with field observations.	PG&E is not required to provide alternative mitigation analyses in its GRC. PG&E will consider alternative mitigation and present alternative mitigation analyses in its EUP. The mitigation values PG&E uses in its analyses are reasonable as they are based on its own internal analyses. It is unclear which "field observations" MGRA is referring to in its recommendation.	See Chapter 3 Section C for the alternatives considered at each phase of the Project Acceptance Framework.

TABLE 7-10
RESPONSE TO ISSUES RAISED BY SAFETY POLICY DIVISION OR PARTIES ON PG&E'S 2024 RAMP
(CONTINUED)

Line No.	Cite to SPD Evaluation Report[(a)]	Issue Raised by SPD or Intervenor	PG&E's 2027 GRC Response	Additional Responsive Information in the EUP
12	Informal Intervenor Comments of The Utility Reform Network, dated October 9, 2024.	PG&E should identify Project-level CBRs by combining adjacent circuit segments, or at minimum identify which circuit segments can be aggregated to create Project-level risk and cost information.	The EUP Guidelines define Project-level as a measurement that accumulates risk from all of the equipment on a single Circuit segment into a single number (Appendix A). PG&E will calculate BCRs at the Project-level (circuit segment) for those circuit segments considered eligible for system hardening in its EUP. BCRs will be calculated for undergrounding, overhead hardening.	See Progress Report 0, Appendix A Table C.12 for Screen 2 table of BCR values.

(a) Citation to SPD Evaluation Report refers to the Chapter 1 Summary of Findings or Recommended Solutions to Address Findings and Deficiencies (Recommended Solution). The Chapter 1 Summary of Findings and Recommended Solutions are on pp. 76 to 82 of the SPD Evaluation Report on PG&E's 2024 RAMP (A.) 24-05-008. Additionally, refer to Attach. D – SPD-37 Data Submission.

P. Chapter Summary

Chapter 7 explains how PG&E meets the EUP Guidelines (Section 2.7) requirements for a risk modeling methodology used to evaluate undergrounding and backtesting. It describes an integrated framework centered on four primary models—WDRM, OPRM, Enterprise Bow Tie Model and WBCA—supported by sub-models. Together, these tools quantify wildfire ignition likelihood and consequences at the Circuit Segment level, estimate reliability impacts associated with EPSS and PSPS outage programs, and translate those wildfire risk and reliability outputs (plus cost and effectiveness assumptions) into BCRs used to inform mitigation selection.

The chapter also outlines how the methodology supports required use cases and reporting: Project-level and Aggregate Risk Analysis; evaluation of Ignition and Outage Program Risks both separately and combined, forecasting and accumulation of risk over time (including climate-change considerations and discounting); handling Projects with multiple mitigations/Subprojects; maintaining Baselines, versions, and calibrations; and enabling comparisons across mitigation strategies. We included the required model reports, KDMMs and enterprise diagrams, a definition of the model risk landscape, and other compliance elements (e.g., retention/update schedules, PVM, Portfolio standards, thresholds, and comparative metrics). As discussed in this chapter, we will achieve substantial risk reduction using a data-driven framework that targets Circuit Segments with the greatest Ignition and Outage Program Risk, informed by our wildfire and reliability risk models and Alternative Mitigation analysis.

Q. Chapter 7 Supporting Attachments Index

The following workpapers/attachments listed in Table 7-11 below support this chapter.

TABLE 7-11:
CHAPTER 7 SUPPORTING ATTACHMENTS INDEX

Line No.	EUP Section	EUP Location	Workpaper / Table Name	File Name
1	7.G.1.a 7.K	Attachment B	WP001 (Mitigation Effectiveness Analysis)	PGE_WP001_2026-09-30_Mitigation Effectiveness Analysis_R0
2	7.O	Attachment B	WP003 (Project Prioritization and Decision Tree)	PGE_WP003_2026-09-30_Project Prioritization and Decision Tree_R0
3	7.C.1.b 7.D.5.c 7.D.6.b 7.D.6.c 7.G.4.c 7.H.3	Attachment B	WP006 (Wildfire Benefit Cost Analysis (WBCA) Whitepaper)	PGE_WP006_2026-~~09~~10-30_WBCA Whitepaper_R0
4	7.G.1.a	Attachment B	WP008 (Core Capability 1: Supporting Formulas)	PGE_WP008_2026-09-30_Core Capability 1 Supporting Formulas_R0
5	7.G.2	Attachment B	WP009 (Core Capability 2: Supporting Formulas)	PGE_WP009_2026-09-30_Core Capability 2 Supporting Formulas_R0
6	7.G.3.a	Attachment B	WP010 (Core Capability 3: Supporting Formulas)	PGE_WP010_2026-09-30_Core Capability 3 Supporting Formulas_R0
7	7.D.5.c 7.G.4.a	Attachment B	WP011 (Core Capability 4: Supporting Formulas)	PGE_WP011_2026-09-30_Core Capability 4 Supporting Formulas_R0
8	7.G.5.1	Attachment B	WP012 (Core Capability 5: Supporting Formulas)	PGE_WP012_2026-09-30_Core Capability 5 Supporting Formulas_R0
9	7.G.6.e	Attachment B	WP013 (Core Capability 6: Supporting Formulas)	PGE_WP013_2026-09-30_Core Capability 6 Supporting Formulas_R0
10	7.G.7	Attachment B	WP014 (Core Capability 7: Supporting Formulas)	PGE_WP014_2026-09-30_Core Capability 7 Supporting Formulas_R0

TABLE 7-11
CHAPTER 7 SUPPORTING ATTACHMENTS INDEX
(CONTINUED)

Line No.	EUP Section	EUP Location	Workpaper / Table Name	File Name
11	7.D.1	Attachment B	WP015 (Distribution Event Probability Models Version 4 (DEPM v4))	PGE_WP015_2026-09-30_DEPM v4_R0
12	7.D.3.g	Attachment B	WP016 (EPSS Toy Problem)	PGE_WP016A_2026-09-30_EPSS Toy Problem_R0 PGE_WP016B_2026-09-30_EPSS Toy Problem Calculations_R0
13	7.D.4.g	Attachment B	WP017 (PSPS Toy Problem)	PGE_WP017A_2026-09-30_PSPS Toy Problem_R0 PGE_WP017B_2026-09-30_PSPS Toy Problem Calculations_R0
14	7.D.3.c 7.H.3	Attachment B	WP018 (EUP EPSS Risk Model v1 Documentation)	PGE_WP018_2026-~~09-30~~11-02_EUP EPSS Risk Model v1 Documentation_R0
15	7.C.1.b 7.D.3.a 7.D.3.d 7.D.4.a	Attachment B	WP019 (EUP Outage Program Risk Model v1 Documentation)	PGE_WP019_2026-09-30_EUP Outage Program Risk Model v1 Documentation_R0
16	7.H.2	Attachment B	WP020 (EUP PSPS v1 Risk Model Documentation)	PGE_WP020_2026-09-30_EUP PSPS Risk Model v1 Documentation_R0
17	7.E	Attachment B	WP021 (KDMM Formulas)	PGE_WP021_2026-09-30_KDMM Formulas_R0
18	7.D.6.c	Attachment B	WP022 (PCEEE Risk)	PGE_WP022_2026-07-01_PCEEE Risk_R0.pdf
19	7.C.1.a	Attachment B	WP023 (RaDA Modeling Algorithms and Methodologies)	PGE_WP023 2026-09-30_RaDA Modeling Algorithms and Methodologies v.1 Documentation_R0.pdf
20	7.D.6.g	Attachment B	WP024 (WBCA Toy Problem)	PGE_WP024_2026-09-30_WBCA Toy Problem_R0

TABLE 7-11
CHAPTER 7 SUPPORTING ATTACHMENTS INDEX
(CONTINUED)

Line No.	EUP Section	EUP Location	Workpaper / Table Name	File Name
21	7.D.2.a 7.D.2.b 7.D.2.e	Attachment B	WP025 (Wildfire Consequence Model Version 4 (WFC v4) documentation)	PGE_WP025_2026-09-30_WFC v4 Documentation_R0
22	7.C.1.b 7.D.2.d	Attachment B	WP026 (Wildfire Distribution Risk Model Version 4 (WDRM v4) Documentation)	PGE_WP026_2026-09-30_WD RM v4 Documentation_R0
23	7.D.7.f 7.D.7.g	Attachment B	WP027 (Wildfire Bow Tie Toy Problem)	PGE_WP027_2026-09-30_Wildf ire Bow Tie Toy Problem_R0
24	7.D.2.c 7.D.2.e 7.D.2.g	Attachment B	WP028 (Ignition Consequence Toy Problem)	PGE_WP028_2026-09-30_Igniti on Consequence Toy Problem_R0
25	7.D.1.g	Attachment B	WP029 (Ignition Likelihood Toy Problem)	PGE_WP029_2026-09-30_Igniti on Likelihood Toy Problem_R0
26	7.D.5.g	Attachment B	WP031 (OUR Toy Problem)	PGE_WP031_2026-09-30_OUR Toy Problem_R0
27	7.F	Attachment A-4	JSON Data Submission: Model Risk Landscapes for Projects	PGE_Initial_2026-~~09~~10-30_Proj ects_R0
28	7.H 7.K 7.L 7.N	Attachment A-1	Portfolio Coversheet	PGE_AtchA_2026-~~09~~10-30_Pro gress Report 0 Portfolio Coversheet_R0
29	7.K	Attachment A-3	JSON Data Submission: PVMs	PGE_Initial_2026-09-30_PVM_ R0
30	7.O	Attachment D	SPD-37 Data Submission	PGE_Initial_2026-~~09-30~~11-02_A ttachment D_R0

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 8

MODEL RETENTION AND UPDATE SCHEDULE

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 8
MODEL RETENTION AND UPDATE SCHEDULE

A. Introduction

This chapter addresses the following issues raised in Section 2.7.6 of the Electrical Undergrounding Plan (EUP) Guidelines: the schedule for updates to Pacific Gas and Electric Company's (PG&E) Risk Modeling Methodology, the timing and contents of reports on any new models or model updates, backtest of the models on Key Decision-Making Metrics (KDMM), the establishment of a new Baseline, and updates to risk scores for new equipment.

Section B lists the requirements of the EUP Guidelines addressed in this Chapter.

Section C explains PG&E's established risk model version and calibration update processes and notes the differences between the two. PG&E discusses the bases for version updates and calibration for the following four models: (1) Wildfire Distribution Risk Model (WDRM), (2) Outage Program Risk Model (OPRM), (3) Wildfire Benefit Cost Analysis (WBCA) Model; and (4) Enterprise Bow Tie Model.[196] PG&E provides an overview of our Risk Modeling Methodology and our documentation and retention of the model data.

Section D includes a summary of chapter 8 and Section E lists the attachments that support chapter 8.

B. Undergrounding Plan Requirements

In Tables 8-1 and 8-2 below, we identify the EUP Guidelines requirements that are addressed in this chapter. There are no Senate Bill (SB) 884 requirements addressed in this chapter.

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[196] The four key models describe PG&E's overall risk modeling methodology. The seven model chapters outlined in Chapter 7 Section D provide the required model-by-model detail underlying the risk modeling methodology, this includes models that are inputs to the key models. WDRM is documented through separate Ignition Likelihood and Ignition Consequence chapters (Model Report Chapters 1 and 2); OPRM is documented through separate EPSS and PSPS chapters (Model Report Chapters 3a and 3 b); and the remaining chapters explain the Overall Utility Risk calculation (Model Report Chapter 4), the WBCA (Model Report Chapter 5), and the Enterprise Bow Tie Model (Model Report Chapter 6).

TABLE 8-1:
SB 884 REQUIREMENTS ADDRESSED IN CHAPTER 8

Line No.	Public Utilities Code Section	Legislative Requirement	Where Requirement is Addressed
1	N/A	N/A	N/A

TABLE 8-2:
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS ADDRESSED IN CHAPTER 8

Line No.	EUP Guidelines Section	EUP Guidelines Requirement	Requirement Reference in Chapter 8
1	2.7.6	Model Retention and Update Schedule	Section C

C. Model Retention and Update Schedule (EUP Guidelines Section 2.7.6)

The Large Electrical Corporation must establish model and calibration retention policies. The Large Electrical Corporation must retain models and calibrations data for the lifetime of the program.

The Large Electrical Corporation must describe its plan to update its Risk Modeling Methodology, including details regarding how and when model version and calibration updates are planned. Any new version or calibration will require a new risk_model_version_id and risk_model_calibration_id in the data submission, respectively. See Appendix C of these Guidelines for more details.

When a new model or model version is introduced to the Risk Modeling Methodology, after the approval of an EUP, the Large Electrical Corporation must submit a Model Report (as described in Sections 2.7.2 and 2.7.5.2 of these Guidelines) as a subsection of the Progress Report to Energy Safety as well as an historical backtest of the new model's impact on all KDMMs for all Baselines since the start of the EUP (Appendix C, Section C.1.5).

In each Model Report, including in Progress Report 0 and subsequent Progress Reports, the Large Electrical Corporation must establish a new Baseline which reflects the existing distribution system as detailed in Section 2.7.5 of these Guidelines.

Risk scores for new equipment/alignment must be reported in the same granularity, scale, and methodology as previously existing equipment. These evaluations must be conducted in accordance with the Large Electrical Corporation's Risk Modeling Methodology, as described in the EUP, in cases where the Large Electrical corporation has not re-evaluated the risk on the new equipment.

In this section, we discuss the bases for version updates and calibration for the following four models: (1) WDRM, (2) OPRM, (3) WBCA; and (4) Enterprise Bow Tie. PG&E provides an overview of our Risk Modeling Methodology and our documentation and retention of the model data. Consistent with the EUP Guidelines, PG&E distinguishes between risk model version updates, which reflect substantive or structural changes to a model methodology, and risk model calibration updates, which are used to keep an approved model current and accurate without materially altering its structure or logic.[197]

Under the EUP Guidelines, a risk model version represents a qualitatively distinct configuration of the utility's Risk Modeling Methodology.[198] A version change occurs when the structure, methodology, or composition of the risk modeling system is materially altered such that the way risk is evaluated meaningfully changes. Version changes are substantive in nature and are not limited to routine data updates. A version change reflects a fundamental shift in how risk is modeled, such as the addition or removal of component models, replacement of an existing model with a different analytical approach, retraining of complex machine-learning models, or implementation of a new optimization or modeling methodology.

By contrast, a risk model calibration under the EUP Guidelines is a more limited update that does not materially alter the structure or operation of the Risk Modeling Methodology.[199] Calibration changes are intended to keep an existing model current and accurate by adjusting inputs, parameters, or datasets, while preserving the underlying modeling framework.

The EUP Guidelines expressly distinguish between calibration updates and version changes. Calibration updates may include, for example, updating historical input data, correcting minor coding errors, cleaning or refining datasets, or updating Project Variable Modifiers using an already-approved methodology. While these updates may affect numerical outputs, they do not

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197 Office of Energy Infrastructure Safety, 10-Year Electrical Undergrounding Plan Guidelines (Feb. 20, 2025) (EUP Guidelines), § 2.7.5.2 – Version and Calibration Changes.

198 EUP Guidelines, § 2.7.5.2.

199 EUP Guidelines, § 2.7.5.2.

significantly alter the Model Risk Landscape or the logic by which risk is calculated.[200]

Table 8-3 below summarizes the EUP requirements between Risk Model versions and Risk Model calibrations.

TABLE 8-3:
SUMMARY OF REQUIREMENTS FOR A RISK MODEL VERSION VS. RISK MODEL CALIBRATION CHANGE

Line No.	Topic	Risk Model Version	Risk Model Calibration
1	Nature of change	Qualitative, structural, or methodological change	Quantitative or data-level update
2	Effect on modeling logic	Substantially changes how risk is evaluated	Does not materially change modeling logic
3	Examples (from Guidelines)	Adding/removing models; replacing a model; retraining a neural network; new optimization methodology	Updating historical tables; fixing minor code errors; cleaning input data; updating PVMs using approved methods
4	New Model Report Provided	Yes	No
5	New Baseline	Yes	Yes
6	Historical Backtesting Provided	Yes	No
7	Update Cadence	WDRM, OPRM, WBCA: Aligned with WMP cycles w/ discretion (e.g., new regulatory requirements)	WDRM, OPRM, WBCA: Aligned with timing of version updates for associated models

PG&E's four risk models and the components, versions, and anticipated calibration updates are described below.

1. Model Updates and Calibration Updates

a. WDRM

1) Version Updates

A new version of the WDRM represents a substantive change to the Risk Modeling Methodology that materially affects how wildfire risk is evaluated. Version updates may include, for example:

[200] EUP Guidelines, § 2.7.5.2.

- Retraining the component ignition event probability models to the latest available historical records for failure, outage, and ignition events;
- Retraining the wildfire consequence model with updated historical fire outcomes;
- Structural changes to component ignition probability or consequence models;
- Replacement of an existing analytical approach with a new methodology; or
- Introduction of new modeling components that materially alter the risk framework.

2) Calibration Updates

For the WDRM specifically, calibration updates are unlikely. If we did a calibration update, this would also trigger a version update to the model. With each calibration update, PG&E may:

- Refresh input datasets, parameters, or attributes using existing, approved methodologies; or
- Correct minor coding or data issues that do not alter modeling logic.

b. Outage Program Risk Model

1) Version Updates

A new version of the OPRM occurs when substantive changes are made to the model's structure or methodology and refreshed typically in connection with a new WDRM version. Examples include:

- Incorporation of materially revised WDRM outputs or structure;
- Updates to the outage risk framework that materially change how reliability impacts are assessed; or
- Structural changes to model logic or analytical approach.

2) Calibration Updates

Calibration updates keep the OPRM current without materially altering its structure. These updates may include:

- Refreshing input datasets consistent with updated WDRM outputs;
- Updating outage-related parameters using new or updated historical data; or
- Minor refinements that do not change the underlying modeling logic.

c. WBCA Model

1) Version Updates

A WBCA version update reflects a substantive change to the model's structure, logic, or functionality. Examples include:

- Changes to the decision framework used to compare mitigation alternatives;
- Introduction of new analytical functionality or materially revised benefit-cost logic; or
- Structural code changes are required to implement new regulatory requirements or methodologies.

2) Calibration Updates

Calibration updates refresh WBCA inputs while preserving the approved model structure. These updates may include:

- Updates to mitigation effectiveness values;
- Updates to financial inputs such as discount rates or cost assumptions;
- Refreshes to wildfire risk or outage risk inputs sourced from updated models; or
- Updates to climate-related inputs using approved methodologies.

d. Enterprise Bow Tie Model

1) Version Updates

An Enterprise Bow Tie version update reflects a substantive change to the model's structure, logic, or functionality. Examples include:

- Introduction of new analytical functionality or materially revised logic; or

- Structural code changes are required to implement new regulatory requirements or methodologies.

2) Calibration Updates

Calibration updates refresh Enterprise Bow Tie inputs while preserving the approved model structure. These updates may include:

- Updates to mitigation effectiveness values;
- Updates to financial inputs such as discount rates and value of service;
- Updating data parameters using new or updated historical data;
- Refreshes to wildfire risk or outage risk inputs sourced from updated models or analysis; or
- Updates to climate-related inputs using approved methodologies.

2. Documentation

For all risk models, version updates are documented in applicable model technical documentation and/or supporting workpapers, including descriptions of methodological changes, assumptions, model configuration, code, and data inputs.[201] Calibration updates including training datasets, input datasets, and related documentation are archived upon approval.

3. Risk Modelling Methodology and Update Schedule

The EUP Guidelines describe Risk Modeling Methodology as the basis for comparing the potential wildfire risk and reliability impacts of undergrounding to Alternative Mitigations and Additional Comparisons.[202]

PG&E provides an overview of our Risk Modeling Methodology below. PG&E plans to update the version of the WDRM, OPRM, WBCA and Enterprise Bow Tie Model in alignment with PG&E's 2031-2034 WMP and

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[201] See Attach. B, WP006 (WBCA Whitepaper), Attach. B, WP019 (EUP Outage Program Risk Model v1 Documentation), Attach. B, WP026 (WDRM Documentation) and Attach. B, WP027 (Wildfire Bow Tie Toy Problem).

[202] EUP Guidelines § 2.7.5.

General Rate Case cycles starting in 2028.[203] However, PG&E may also initiate mid-cycle risk model version updates should substantive changes warrant such action or if new functionality is required. These substantive changes may be driven by regulatory requirements or new understandings of risk.

PG&E anticipates making calibration updates to our models as part of each version release. PG&E retains the discretion to make calibration changes if it deems appropriate based on new data. Table 8-4 shows the planned model and calibration update schedule for each risk model.

TABLE 8-4:
RISK MODEL VERSION AND CALIBRATION UPDATE SCHEDULE

Line No.	Risk Model	Risk Model Version	Risk Model Calibration
1	WDRM	Aligned with WMP cycles starting in 2028 with discretion to make other version changes (e.g., new regulatory requirements)	Aligned with timing of version releases for associated models with discretion to make other calibrations.
2	OPRM		
3	WBCA		
4	Enterprise Bow Tie	Aligned with RAMP and GRC cycles starting in 2028 with discretion to make other version changes (e.g., new regulatory requirements)	

4. New Version and Risk Model Naming System

When PG&E introduces a new risk model version, a corresponding risk_model_version_id and risk_model_calibration_id will be required as part of PG&E's regulatory data submissions. These identifiers will be reported in the EUP data tables, including: (1) Table C.3, Risk Model Version History Table, and (2) Table C.10, Project Table Construction and Data Requirements.

PG&E will assign risk model version identifiers using a standardized naming convention. Each model release is assigned a version number in the format v#, where # is a sequential, ascending integer (e.g., v1, v2, v3). Calibrations are performed as part of each model version release and

[203] PG&E does not have sufficient time to update the WDRM for the 2028-2030 WMP which is due in 2027.

generally typically do not occur as standalone updates. However, if a calibration is performed independently of a model release, PG&E assigns a calibration number in the format c#, where # is a sequential, ascending integer representing the approved calibration.

The version and calibration identifiers are appended to the Risk Model name, separated by an underscore in the following format: MODEL_v[#]c[#]. As a result, the reported identifier reflects both the current model version and calibration. For example, in Progress Report 0, PG&E will report WBCA_v1c0 as the applicable risk_model_calibration_id, indicating Risk Model version 1 with no standalone calibration updates since its release.

Table 8-5 below summarizes the naming convention used to identify risk model versions and associated calibration identifiers.

TABLE 8-5:
RISK MODEL VERSION AND CALIBRATION ID STANDARD EXAMPLES

Line No.	Risk Model	version_id	risk_model_calibration_id	Other Naming Variations
1	ID Standard	MODEL_v[#]c[#]	MODEL_v[#]c[#]	
2	WDRM	WDRM_v4c0	WDRM_v4c0	WDRM v4
3	OPRM	OPRM_v1c0	OPRM_v1c0	OPRM v1
4	WBCA[(a)]	WBCA_v1c0	WBCA_v1c0	WBCA v1
5	Bow Tie Model	Bow Tie Model v.Oct2026c0	Bow Tie Model v.Oct2026_c0	Enterprise Risk Bow Tie Model

(a) The WBCA is PG&E's primary decision-making and reporting Risk Model, as outputs from the WDRM and OPRM are incorporated into the WBCA.

5. Model Report and Historical Backtest When a New Model or Version Is Introduced

When PG&E introduces a new model or new model version to the Risk Modeling Methodology after approval of the EUP, we will submit a Model Report as a subsection of a Progress Report with a historical backtest of the new model's impact on all KDMMs for all Baselines and Portfolios since the start of the EUP. (See Risk Model Backtesting Table C.5 in Progress Report 0, Attach. A-2.) PG&E discusses backtesting in Chapter 6, Section C.1.b.5.

6. New Distribution System Configuration Baseline Requirements

PG&E will establish a new Baseline annually that reflects the existing distribution system. The new Baseline will account for the risk reduced by system hardening in the prior year. The new Baseline will be reported in each Model Report including Progress Report 0 and subsequent Progress Reports.

7. New Equipment and/or Alignment Reporting Requirements

PG&E currently reports risk at the Circuit Segment level and will continue to do so in future model updates and calibrations to ensure consistency in granularity, scale, and methodology across both existing and newly evaluated equipment. In accordance with the Risk Modeling Methodology described in Chapter 7, risk assessments for new equipment or alignments will be conducted using the same framework as previously evaluated assets, unless and until a full reevaluation of system risk is performed. This approach maintains methodological consistency and enables comparable risk reporting across the Portfolio.

8. Model Version and Calibration Retention Schedule

PG&E will retain all model versions, calibration datasets, and associated documentation for the life of the EUP.

D. Chapter Summary

This chapter explains PG&E's plan for retaining and updating the risk models used to support the EUP and addresses the requirements in Section 2.7.6 of the EUP Guidelines. We distinguish between risk model version updates, which involve substantive methodological or structural changes, and calibration updates, which refresh data, parameters, or assumptions without materially changing model logic. The chapter applies this framework to four key models: (1) WDRM, (2) OPRM, (3) WBCA, and (4) Enterprise Bow Tie Model.

The chapter also explains how and when we will update our models and associated reporting. For new model versions, PG&E will use updated model names and calibration IDs, provide model reports, and show how changes affect KDMMs using backtesting. Each year, PG&E will also report updated Baselines and risk scores for any new equipment or alignments.

E. Chapter 8 Supporting Attachments Index

The workpapers/attachments in Table 8-6 below support this chapter.

TABLE 8-6:
CHAPTER 8 SUPPORTING ATTACHMENTS/WORKPAPERS INDEX

Line No.	EUP Section	EUP Location	Workpaper/Table Name	File Name
1	8.C.2	Attachment B	WP006 (WBCA Whitepaper)	PGE_WP006_2026-~~09~~10-30_WBCA Whitepaper_R0
2	8.C.2	Attachment B	WP019 (EUP Outage Program Risk Model v1 Documentation)	PGE_WP019_2026-09-30_EUP Outage Program Risk Model v1 Documentation_R0
3	8.C.2	Attachment B	WP026 (WDRM v4 Documentation)	PGE_WP026_2026-09-30_WDRM v4 Documentation_R0
4	8.C.2	Attachment B	WP027 (Wildfire Bow Tie Toy Problem)	PGE_WP027_2026-09-30_Wildfire Bow Tie Toy Problem_R0
5	8.C.4.	Attachment A-2	Table C.3 Risk Model Version History Table	PGE_Initial_2026-09-30_T3_R0
6	8.C.4.	Attachment A-2	Table C.10 Project Table	PGE_Initial_2026-09-30_T10_R0
7	8.C.5	Attachment A-2	Table C.5 Risk Model Backtesting Table	PGE_Initial_2026-09-30_T5_R0

PACIFIC GAS AND ELECTRIC COMPANY

ELECTRICAL UNDERGROUNDING PLAN

CHAPTER 9

REPORTING METRICS

PACIFIC GAS AND ELECTRIC COMPANY
ELECTRICAL UNDERGROUNDING PLAN
CHAPTER 9
REPORTING METRICS

A. Introduction

This chapter addresses requirements in the Electrical Undergrounding Plan (EUP) Guidelines Section 2.8, including the required reporting metrics, data validation, the Portfolio Coversheet, and the Key Decision-Making Metrics (KDMM) tables and graphs in in the Portfolio Coversheet. This chapter also describes how we will track changes to our Portfolio of Undergrounding Projects over the duration of the EUP. Below is a summary of the subsequent sections in this chapter:

Section B lists the requirements in Senate Bill (SB) 884 and the EUP Guidelines addressed in this chapter.

Section C provides the reporting metrics included in EUP Guidelines Section 2.8.4 and 2.8.5.

Section D addresses reporting requirements and naming conventions.

Sections E and H provide an overview of the Portfolio Coversheet, the organization of the Portfolio Coversheet and our plans to update it.

Section F includes System and Portfolio Level Risk Matrices and Profiles for KDMMs.

Section G discusses Portfolio Development and how we will track changes to the Portfolio over time.

Section I provides a summary and Section J lists the attachments supporting this chapter.

B. Undergrounding Plan Requirements

Progress Report 0 requirements are addressed in Chapters 6 and 9 pursuant to the EUP Guidelines. In Tables 9-1 and 9-2 below, we identify the EUP Guidelines addressed in this chapter. There are no statutory requirements addressed in this chapter.

TABLE 9-1:
SB 884 REQUIREMENTS ADDRESSED IN CHAPTER 9

Line No.	Public Utilities Code Section	Legislative Requirement	Where Requirement is Addressed
1	None	None	N/A

TABLE 9-2:
ENERGY SAFETY EUP GUIDELINES REQUIREMENTS

Line No.	EUP Guidelines Section	EUP Guidelines Requirement	Chapter Reference
1	2.8	Reporting Metrics	Section C
2	2.8.1	Tabular Data Submission	Chapter 6 Section C. 1.b.
3	2.8.2	JSON Data Submission	Chapter 6 Section C.1.c
4	2.8.3	Spatial Data Reporting for Projects	Chapter 6 Section C 1.d
5	2.8.4	Data Validation	Section C.4
6	2.8.5	Risk Model Methodology Verification Data	Section C.5
7	2.8.5.1	Model Risk Landscape Variables Table	Section C.5.a
8	2.8.5.2	Reporting Project Variables Modifiers	Section C.5.b
9	2.8.5.3	Verifying and Validating New Model Versions	Section C.5.c
10	2.8.6	Reporting a Portfolio of Undergrounding Projects	Section D
11	2.8.6.1	Portfolio Coversheet Overview	Section E
12	2.8.6.2	System and Portfolio-Level Risk Matrices and Profiles for Key Decision-Making Metrics	Section F
13	2.8.6.3	Portfolio Development	Section G
14	2.8.6.4	Portfolio Coversheet Organization	Section H

C. Reporting Metrics (EUP Guidelines Section 2.8)

This section contains detailed instructions on how the Large Electrical Corporation will report on its Risk Modeling Methodology, Portfolio of Undergrounding Projects, individual Undergrounding Projects, development of new models, and non model based projections. Template files for use by the Large Electrical Corporation will be made available on Docket #2023 UPs at Energy Safety's website. Where possible, Energy Safety and the CPUC reporting requirements will be streamlined and consistent.

1. Tabular Data Submission (EUP Guidelines Section 2.8.1)

Progress Report 0 and each subsequent Progress Report must include the following tables and reflect the most current information as of each Progress Report submission:

a. *A Plan Table identifying information about the Large Electrical Corporation, the EUP, and thresholds. This table is not modified during Progress Reports.*

b. *A KDMM Table listing all KDMMs used by the Large Electrical Corporation in its EUP, with explanations. This table is not modified during Progress Reports.*

c. *A Risk Model Version History Table listing and describing all iterations of the risk model versioning and calibration to date.*

d. *A Portfolio Table that summarizes the Undergrounding Projects at the System Level and Portfolio Level.*

e. *A Risk Model Backtesting Table listing risk models versioning and calibration information, along with their corresponding KDMM values for each version and calibration.*

f. *A Circuit Segment Identification Table that summarizes identifying information for each Circuit Segment in the utility service territory.*

g. *A Circuit Segment Changelog Table that tracks changes to Circuit Segment IDs and/or Circuit Segment lengths.*

h. *A Circuit Segment Risk Score Table that summarizes the risk values for each Circuit Segment in the utility service territory.*

i. *A Screen History Table tracking the progress of each Circuit Segment through the multiple screens required before an Undergrounding Project is constructed.*

j. *A Project Table for each project, after passing Screen 2, that details each Undergrounding Project, including risk tranching, selection justification, and location at the county and division level.*

k. *A Screen 2 Table comparing the cost and benefit information for each project, after passing Screen 2, against multiple Alternative Mitigations.*

l. *A Screen 3 Table comparing the detailed risk modeling projections for each project, after passing Screen 3, against multiple Alternative Mitigations.*

m. *A Screen 4 Table comparing the cost and benefit information of the fully scoped Confirmed Project, and the final combination of Alternative Mitigations used in Screen 3.*

n. *A Subproject Table listing Subproject IDs, their mitigation selection, and construction information for all Subprojects that are part of Confirmed Projects that have passed Screen 4.*

o. *A Project Index Table which summarizes the project information in an easily searchable format. See Appendix C.1.15 of these Guidelines for details.*

Details about each table, the requirements for the submission, and other instructions are found in Appendix C.1 of these Guidelines.

Progress Report 0 includes the required tables listed in Section 2.8.1 (items a-o) of the EUP Guidelines using the templates posted on Energy Safety's website. The tabular data submission is appended to Progress Report 0 as Attach. A-2 (Tabular Data Submissions). Pursuant to EUP Guidelines Sections 2.6 and 2.6.1 (i), our discussion of the tables in the Progress Report is in Chapter 6, Section C.

2. JSON Data Submission (EUP Guidelines Section 2.8.2)

The Large Electrical Corporation must submit the following JSON data in each Progress Report, including Progress Report 0:

a. Project Variable Modifiers JSON as described in Section 2.8.5.2 and Appendix C of these Guidelines.

b. A Model Risk Landscape JSON, as described in Appendix C of these Guidelines, with information for each project that has passed Screen 3.

These files must reflect the most current information as of each Progress Report submission. Further details on JSON submissions are in Section 3.11 of these Guidelines and in Appendix C.

The Large Electrical Corporation must convert its JSON data submission into Comma Separated Values (CSV) format and host the CSV files on a publicly available webpage dedicated to its EUP, as described in Section 3.8.1 of these Guidelines.

The JSON submission is addressed in Chapter 6, Section C.1.c and is included as EUP Attach. A-3 (JSON Data Submission: Project Variable Modifiers) and EUP Attach. A-4 (JSON Data Submissions: Model Risk Landscapes for Projects).

3. Spatial Data Reporting for Projects (EUP Guidelines Section 2.8.3)

The Large Electrical Corporation must report additional modeling and Project Level data through a geodatabase submission. This information will identify isolatable Circuit Segments, Undergrounding Projects, overhead lines that will be deenergized after completion of projects, and critical pieces of infrastructure equipment. The Large Electrical Corporation must update information reported in geodatabase submissions in each Progress Report.

Further details about these submissions are found in Appendix C.3.

Spatial Data Reporting is addressed in Chapter 6, Section C.1.d and is included as Attach. A-5 Geographic Information System (GIS) Data Submissions.

4. Data Validation (EUP Guidelines Section 2.8.4)

Energy Safety will review and validate data and reject data submissions that do not meet the criteria in this section. If a submission fails the validation check and is rejected, the Large Electrical Corporation must correct the errors and resubmit its data as directed by Energy Safety.

Energy Safety will review EUP data submissions according to the following validation criteria:

a. *Data Consistency: Data is properly labeled with unique integer identifiers, and labels remain consistent both within a submission and from one submission to another.*

b. *Structural Integrity: Data conforms to the required types and modes, such that it can be ingested into Energy Safety data systems.*

c. *Completeness: All required components are included in each submission.*

d. *Computational Accuracy: All summations and other data aggregations within the submission are calculated accurately.*

Additionally, when there is no data for a particular field, the Large Electrical Corporation must leave the field null (empty), except where "N/A" is specified and the conditions for its use are met. The Large Electrical Corporation must not place "Unknown," "0," empty spaces, or other placeholders into fields, or use the "Other, see comment" option when no data are available.

PG&E will review our EUP data submissions to check for consistency with Energy Safety's validation criteria. We understand that Energy Safety will review EUP data submissions for data consistency, structural integrity, completeness, and computational accuracy. PG&E will correct any errors and resubmit data as directed by Energy Safety.

5. Risk Modeling Methodology Verification Data (EUP Guidelines Section 2.8.5)

This section describes the numerical and visual elements that the Large Electrical Corporation must submit to establish the veracity of its Risk Modeling Methodology.

a. Model Risk Landscape Variables Table (EUP Guidelines Section 2.8.5.1)

The EUP must include a Model Risk Landscape Variables Table as referenced in Section 2.7 of these Guidelines, that lists each metric in the Large Electrical Corporation's Model Risk Landscape per the example below and report values at the highest available resolution. This table must include the numerical type of each metric, which risk factors that it addresses, the resolution of the modeling, indicate whether the metric is considered a KDMM, and identify what other metric(s) it is a precursor for.

PG&E's Model Risk Landscape Variables Table includes the information required in the EUP Guidelines Section 2.8.5.1. It lists each metric in our Model Risk Landscape and includes: (1) the numerical type of each metric; (2) the risk factors addressed; (3) the resolution of the modeling; (4) whether the metric is considered a KDMM; and (5) any metric(s) it is a precursor for. Table 9-3 below is the Model Risk Landscape Variables Table:

TABLE 9-3:
MODEL RISK LANDSCAPE VARIABLES TABLE

Line No.	Field Name	Type	Addresses	Resolution	Is KDMM?	Precursor to Metric(s)
1	Scaled Wildfire Risk post-PSPS and post-EPSS	Risk	Ignition Risk	Per Circuit Segment	No	BCR
2	Scaled PSPS Risk	Risk	PSPS Risk	Per Circuit Segment	No	BCR
3	PCEEE Risk	Risk	PCEEE Risk	Per Circuit Segment	No	BCR
4	Baseline Reliability Risk	Risk	Baseline Reliability Risk	Per Circuit Segment	No	BCR
5	Overall Utility Risk	Risk	OUR	Per Circuit Segment	Yes	N/A
6	Unscaled Wildfire Risk	Risk	Ignition Risk	Per Circuit Segment	Yes	Overall Utility Risk
7	Wildfire Likelihood	Probability	Ignition Risk	Per Circuit Segment	Yes	Wildfire Risk, Overall Utility Risk

TABLE 9-3
MODEL RISK LANDSCAPE VARIABLES TABLE
(CONTINUED)

Line No.	Field Name	Type	Addresses	Resolution	Is KDMM?	Precursor to Metric(s)
8	Wildfire Consequence	Consequence	Ignition Risk	Per Circuit Segment	Yes	Wildfire Risk, Overall Utility Risk
9	Outage Program Risk	Risk	Outage Program Reliability	Per Circuit Segment	Yes	Overall Utility Risk
10	Outage Program Likelihood	Probability	Outage Program Reliability	Per Circuit Segment	Yes	N/A
11	Outage Program Consequence	Back Calculated Consequence[(a)]	Outage Program Reliability	Per Circuit Segment	Yes	N/A
12	EPSS Risk	Risk	EPSS Risk	Per Circuit Segment	No	Outage Program Risk, Overall Utility Risk, BCR
13	EPSS Likelihood	Probability	EPSS Risk	Per Circuit Segment	No	Outage Program Likelihood
14	EPSS Consequence	Back Calculated Consequence[(a)]	N/A	Per Circuit Segment	No	N/A
15	PSPS Risk	Risk	PSPS Risk	Per Circuit Segment	No	Outage Program Risk, Overall Utility Risk
16	PSPS Likelihood	Probability	PSPS Risk	Per Circuit Segment	No	Outage Program Likelihood
17	PSPS Consequence	Back Calculated Consequence[(a)]	N/A	Per Circuit Segment	No	N/A

(a) PSPS and EPSS consequence values are not direct inputs into the Outage Program Risk Model. Instead, they are calculated outputs that result from applying the model's likelihood and risk values. Because of this, PSPS consequence, EPSS consequence, and the overall Outage Program Consequence (which is derived from the PSPS and EPSS consequence values) are formula-driven results, not model inputs

1 See Chapter 7, Section F for more information about Model Risk
2 Landscape Variables.

b. Reporting Project Variables Modifiers (EUP Guidelines Section 2.8.5.2)

The EUP and each Progress Report (including Progress Report 0) must contain a table summarizing the PVMs as referenced in Section 2.7 and Section 2.8.6 of these Guidelines.

The "Mitigation Type" column describes the nature of the work conducted in the project. The Large Electrical Corporation must, at minimum, consider the Alternative Mitigations described in Section 2.7.10. It may include other alternative methods or divide these types of projects into differentiable sub types when appropriate.

The "Model" column indicates which models the PVM effects.

The "Inputs Modified" column describes which of the model inputs are changed.

The "Delta" column describes how the inputs are changed, and may be represented as percentages, changes in distribution, changes in category or any other changes to the inputs that the PVM accomplishes.

The "Other Notes" column contains narrative material that clarifies the way that the PVM affects the inputs.

PG&E defines PVMs as the values used in the WBCA to determine the effectiveness of an Alternative Mitigation at the sub-driver level. Table PCS-6 of the Portfolio Coversheet summarizes the PVM Inputs referenced in Sections 2.7 and 2.8.6 of the EUP Guidelines. Table PCS-6 captures Other Notes, which point to the relevant Workpapers that describe the sub-drivers to each input. Please refer to WP001 for a detailed description of the methodology used to calculate mitigation effectiveness values as shown in the Delta column.

Table PCS-7 includes PVM Outputs. In Table PCS-7, the "Change" column reflects the adjustment to the KDMM values resulting from the application of the mitigation relative to the baseline value. This metric is measured on a systemwide basis. The permanent system hardening mitigation alternatives evaluated in the EUP are modeled as reducing ignition likelihood only. Consequence values remain unchanged for these mitigations because they are driven by underlying factors such as terrain, weather, population exposure, etc. and are therefore represented as N/A. The "Variance" column reflects the variability in mitigation effectiveness across Circuit Segments relative to the

systemwide average change shown in the “Change” column. For example, for OH, the systemwide change in Overall Utility Risk is -38 percent. However, at the Circuit Segment level, individual segment impacts may vary, ranging from -38 percent to +27 percent relative to the systemwide average.

For each mitigation type, PG&E will report in the Portfolio Coversheet the changes to each KDMM resulting from the application of the PVMs. PG&E will update these results when Risk Model calibrations are made that materially affect PVM inputs, assumptions, or estimated mitigation effectiveness. See Chapter 7, Section K for additional information on PVMs and Chapter 8 for the Risk Model versioning and calibration schedule.

TABLE PCS-6:
PROJECT VARIABLE MODIFIERS INPUT

Line No.	Mitigation	Model	Input I.D.	Inputs Modified	Delta[(a)]	Other Notes
1	OH	Ignition Likelihood	1	Vegetation (Branch)	-49%	Attach. B, WP015, Section 3.5.2.3.1
2			2	Vegetation (Trunk)	-25%	Attach. B, WP015, Section 3.5.2.3.2
3			3	Vegetation (other)	-60%	Attach. B, WP015, Section 3.5.2.3.3
4			4	Animal (Bird)	-65%	Attach. B, WP015, Section 3.5.2.1.1
5			5	Animal (Squirrel)	-71%	Attach. B, WP015, Section 3.5.2.1.2
6			6	Animal (other)	-64%	Attach. B, WP015, Section 3.5.2.1.3
7			7	Third Party (Balloon)	-67%	Attach. B, WP015, Section 3.5.2.2.1
8			8	Third Party (Vehicle)	-42%	Attach. B, WP015, Section 3.5.2.2.2
9			9	Third Party (other)	-24%	Attach. B, WP015, Section 3.5.2.2.3
10			10	Primary Conductor – Line Slap	-57%	Attach. B, WP015, Section 3.5.1.4.1
11			11	Primary Conductor – Wire Down	-13%	Attach. B, WP015, Section 3.5.1.4.2
12			12	Primary Conductor – Other	-54%	Attach. B, WP015, Section 3.5.1.4.3
13			13	Secondary Conductor	-50%	Attach. B, WP015, Section 3.5.1.5
14			14	Equipment (Support Structure)	-52%	Attach. B, WP015, Section 3.5.1.6.2
15			15	Equipment (Transformer)	-74%	Attach. B, WP015, Section 3.5.1.8.2
16			16	Equipment (Voltage Control)	-8%	Attach. B, WP015, Section 3.5.1.9
17			17	Equipment (other)	-49%	Attach. B, WP015, Section 3.5.1.10

TABLE PCS-6
PROJECT VARIABLE MODIFIERS INPUTS
(CONTINUED)

Line No.	Mitigation	Model	Input I.D.	Inputs Modified	Delta[a]	Other Notes
18	OH (cont.)	Ignition Likelihood (cont.)	18	Equipment (Capacitor)	-5%	Attach. B, WP015, Section 3.5.1.1
19			19	Equipment (DPD)	-9%	Attach. B, WP015, Section 3.5.1.2
20			20	Equipment (Fuse)	-57%	Attach. B, WP015, Section 3.5.1.3
21			21	Equipment (Switch)	-56%	Attach. B, WP015, Section 3.5.1.7
22		PSPS Likelihood[b]	1	N/A	0%	Attach. B, WP020, Section 3.7
23		EPSS Likelihood[b]	1	N/A	-52%	Attach. B, WP018, Section 3.3
24	UG Primary	Ignition Likelihood	1	Vegetation (Branch)	-95%	Attach. B, WP015, Section 3.5.2.3.1
25			2	Vegetation (Trunk)	-95%	Attach. B, WP015, Section 3.5.2.3.2
26			3	Vegetation (other)	-93%	Attach. B, WP015, Section 3.5.2.3.3
27			4	Animal (Bird)	-100%	Attach. B, WP015, Section 3.5.2.1.1
28			5	Animal (Squirrel)	-100%	Attach. B, WP015, Section 3.5.2.1.2
29			6	Animal (other)	-98%	Attach. B, WP015, Section 3.5.2.1.3
30			7	Third Party (Balloon)	-100%	Attach. B, WP015, Section 3.5.2.2.1
31			8	Third Party (Vehicle)	-98%	Attach. B, WP015, Section 3.5.2.2.2
32			9	Third Party (other)	-48%	Attach. B, WP015, Section 3.5.2.2.3
33			10	Primary Conductor – Line Slap	-98%	Attach. B, WP015, Section 3.5.1.4.1
34			11	Primary Conductor – Wire Down	-100%	Attach. B, WP015, Section 3.5.1.4.2

TABLE PCS-6
PROJECT VARIABLE MODIFIERS INPUTS
(CONTINUED)

Line No.	Mitigation	Model	Input I.D.	Inputs Modified	Delta[(a)]	Other Notes
35	UG Primary (cont.)	Ignition Likelihood (cont.)	12	Primary Conductor – Other	-100%	Attach. B, WP015, Section 3.5.1.4.3
36			13	Secondary Conductor	-50%	Attach. B, WP015, Section 3.5.1.5
37			14	Equipment (Support Structure)	-100%	Attach. B, WP015, Section 3.5.1.6.2
38			15	Equipment (Transformer)	-100%	Attach. B, WP015, Section 3.5.1.8.2
39			16	Equipment (Voltage Control)	-95%	Attach. B, WP015, Section 3.5.1.9
40			17	Equipment (other)	-86%	Attach. B, WP015, Section 3.5.1.10
41			18	Equipment (Capacitor)	-81%	Attach. B, WP015, Section 3.5.1.1
42			19	Equipment (DPD)	-94%	Attach. B, WP015, Section 3.5.1.2
43			20	Equipment (Fuse)	-100%	Attach. B, WP015, Section 3.5.1.3
44			21	Equipment (Switch)	-96%	Attach. B, WP015, Section 3.5.1.7
45		PSPS Likelihood[(b)]	1	N/A	-100%	Attach B, WP020, Section 3.7
46		EPSS Likelihood[(b)]	1	N/A	-100%	Attach B, WP018, Section 3.3
47	Remote Grid	Ignition Likelihood	1	Vegetation (Branch)	-95%	Attach. B, WP015, Section 3.5.2.3.1
48			2	Vegetation (Trunk)	-95%	Attach. B, WP015, Section 3.5.2.3.2
49			3	Vegetation (other)	-93%	Attach. B, WP015, Section 3.5.2.3.3
50			4	Animal (Bird)	-100%	Attach. B, WP015, Section 3.5.2.1.1
51			5	Animal (Squirrel)	-100%	Attach. B, WP015, Section 3.5.2.1.2

TABLE PCS-6
PROJECT VARIABLE MODIFIERS INPUTS
(CONTINUED)

Line No.	Mitigation	Model	Input I.D.	Inputs Modified	Delta[(a)]	Other Notes
52	Remote Grid (cont.)	Ignition Likelihood (cont.)	6	Animal (other)	-98%	Attach. B, WP015, Section 3.5.2.1.3
53			7	Third Party (Balloon)	-100%	Attach. B, WP015, Section 3.5.2.2.1
54			8	Third Party (Vehicle)	-98%	Attach. B, WP015, Section 3.5.2.2.2
55			9	Third Party (other)	-48%	Attach. B, WP015, Section 3.5.2.2.3
56			10	Primary Conductor - Line Slap	-98%	Attach. B, WP015, Section 3.5.1.4.1
57			11	Primary Conductor - Wire Down	-100%	Attach. B, WP015, Section 3.5.1.4.2
58			12	Primary Conductor - Other	-100%	Attach. B, WP015, Section 3.5.1.4.3
59			13	Secondary Conductor	-50%	Attach. B, WP015, Section 3.5.1.5
60			14	Equipment (Support Structure)	-100%	Attach. B, WP015, Section 3.5.1.6.2
61			15	Equipment (Transformer)	-100%	Attach. B, WP015, Section 3.5.1.8.2
62			16	Equipment (Voltage Control)	-95%	Attach. B, WP015, Section 3.5.1.9
63			17	Equipment (other)	-86%	Attach. B, WP015, Section 3.5.1.10
64			18	Equipment (Capacitor)	-81%	Attach. B, WP015, Section 3.5.1.1
65			19	Equipment (DPD)	-94%	Attach. B, WP015, Section 3.5.1.2
66			20	Equipment (Fuse)	-100%	Attach. B, WP015, Section 3.5.1.3
67			21	Equipment (Switch)	-96%	Attach. B, WP015, Section 3.5.1.7

TABLE PCS-6
PROJECT VARIABLE MODIFIERS INPUTS
(CONTINUED)

Line No.	Mitigation	Model	Input I.D.	Inputs Modified	Delta[a]	Other Notes
68	Remote Grid (cont.)	PSPS Likelihood[b]	1	N/A	-100%	Attach B, WP020, Section 3.7
69		EPSS Likelihood[b]	1	N/A	-100%	Attach B, WP018, Section 3.3

(a) Please refer to WP001 for a detailed description of the methodology used to calculate mitigation effectiveness values which are detailed in the Delta column.

(b) Mitigation Effectiveness for both PSPS and EPSS Likelihood is applied uniformly across all circuit segments and is not evaluated at the subdriver-level.

TABLE PCS-7:
PROJECT VARIABLE MODIFIERS OUTPUTS

Line No.	Mitigation	KDMM	Change[(a)]	Variance[(b)]
1	OH	Overall Utility Risk	-38%	-38% / +27%
2		Ignition Risk	-42%	-33% / +23%
3		Ignition Likelihood	-44%	-35% / +21%
4		Ignition Consequence	N/A	N/A
5		Outage Risk	-37%	-37% / +15%
6		Outage Likelihood	-19%	-19% / +33%
7		Outage Consequence	N/A	N/A
8	UG Primary	Overall Utility Risk	-98%	-30% / +2%
9		Ignition Risk	-93%	-24% / +7%
10		Ignition Likelihood	-92%	-24% / +7%
11		Ignition Consequence	N/A	N/A
12		Outage Risk	-100%	0%
13		Outage Likelihood	-100%	0%
14		Outage Consequence	N/A	N/A
15	Remote Grid	Overall Utility Risk	-98%	-30% / +2%
16		Ignition Risk	-93%	-24% / +7%
17		Ignition Likelihood	-92%	-24% / +7%
18		Ignition Consequence	N/A	N/A
19		Outage Risk	-100%	0%
20		Outage Likelihood	-100%	0%
21		Outage Consequence	N/A	N/A

(a) The “Change” column reflects the adjustment to the KDMM values resulting from the application of the mitigation relative to the baseline value. This metric is measured on a systemwide basis. The permanent system hardening mitigation alternatives evaluated in the EUP are modeled as reducing ignition likelihood only. Consequence values remain unchanged for these mitigations because they are driven by underlying factors such as terrain, weather, population exposure, etc. and are therefore represented as N/A.

(b) The “Variance” column reflects the variability in mitigation effectiveness across Circuit Segments relative to the systemwide average change shown in the “Change” column.

c. Verifying and Validating New Model Versions (EUP Guidelines Section 2.8.5.3)

If the Large Electrical Corporation changes its Risk Modeling Methodology in a way that triggers a versioning update, it must backtest the new models using historical data back to the start of the EUP. These backtests must include a Project Level analysis of each Confirmed Project that passed through Screen 3 (Project Risk Analysis) in that time. These backtests must also include Portfolio Coversheets corresponding to each calibration employed since the previous update.

The results of these tests must be submitted as an additional data submission following the data schema established in Appendix C.

PG&E understands that if a Risk Modeling Methodology change triggers a version update, we must backtest the new models back to the start of the EUP. These backtests must include a Project-Level analysis of each Confirmed Project that passed through Screen 3 (Project Risk Analysis) during that time. The backtests must also include Portfolio Coversheets corresponding to each calibration employed since the previous update. Results of the backtests will be submitted in the Risk Model Backtesting Table (Progress Report Table C.5 following the data schema required by Appendix C.1.5 of the EUP Guidelines).

D. Reporting a Portfolio of Undergrounding Projects (EUP Guidelines Section 2.8.6)

The Large Electrical Corporation must establish a naming system to track the evolution of the Portfolio over time. Adding or removing any project to or from the Portfolio constitutes a Portfolio update and will be indicated by incrementing some value(s) in name. The plan can only have one Portfolio.

PG&E has established a naming system to track the evolution of the Portfolio over time. PG&E understands that adding or removing any Project to or from the Portfolio constitutes a Portfolio update and that updates will be indicated by incrementing a value in the Portfolio name. Changes will be reported in the Progress Reports.

PG&E's naming system consists of the following:

- The Letter 'P' identifying the EUP Portfolio of Undergrounding Projects; and

- A two-digit number beginning with 00, which represents the Portfolio version, allows PG&E to represent changes to the list of Confirmed Projects by changing the Portfolio ID. The first time PG&E reports additional Projects in the Portfolio in a Progress Report, PG&E will report the full list of Confirmed Projects as of that Progress Report as Portfolio P01, P02, etc.

E. Portfolio Coversheet Overview (EUP Guidelines Section 2.8.6.1)

The Portfolio Coversheet is a text document which summarizes the macro level impacts of the EUP. The Large Electrical Corporation must submit the Portfolio Coversheet in Progress Report 0 and each subsequent Progress Report. The content of the Portfolio Coversheet must be updated with the most up to date information available in each Progress Report.

The figures and tables in the Portfolio Coversheet will summarize the most important aspects of the risk modeling at the System Level and Portfolio Level, and must be accompanied by a data submission as detailed in Appendix C.

The Portfolio Coversheet must include a narrative Section which details the formal definition and calculations of the Portfolio Level Standards as directed in Section 2.7.8 of these Guidelines.

The Portfolio Coversheet must include a narrative of no more than one page explaining why any Circuit Segment in the top 5 percent of Overall Utility Risk by score was not included in the EUP.

The Portfolio Coversheet must include a table showing the instantaneous and cumulative values or scores for each KDMM at 0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 15, 20, 25, 30, 35, 40, 45, 50, and 55 years. The instantaneous values describe the risk at a single moment in time, while the cumulative values indicate the accumulation over a time. Values that do not accumulate over time, such as consequence scores, must be reported as a value at a given time.

This section details content that will be included in the Portfolio Coversheet which will be submitted semi-annually with the Progress Report as Attach. A-1. For clarity, we are labeling tables and figures below with the prefix “PCS” to indicate that they are also included in the Portfolio Coversheet. The figures and tables in the Portfolio Coversheet summarize the most important aspects of the risk modeling at the System Level and Portfolio Level.

1. Macro-Level Impacts

PG&E’s implementation of our EUP will significantly reduce ignition and reliability risk in the High Fire Threat District (HFTD). Implementation of the EUP is expected to reduce Overall Utility Risk by approximately $3.03 million per mile of overhead miles removed over the 55-year life of

undergrounding assets within the HFTD. This assumes that we harden approximately 4,000 miles of overhead distribution lines by moving them underground. Additional overhead lines will be hardened through overhead covered conductor installation and line removal with remote grid; this work will be funded primarily through PG&E's GRCs.

2. System and Portfolio Level Standards

PG&E's Portfolio and System Level Standards are discussed in EUP Chapter 7, Section L in response to EUP Guidelines, Section 2.7.8.

Table PCS-2 below details PG&E's Risk Decrease Standards and Reliability Increase Standards which are included in the Portfolio Coversheet. PG&E will update Table PCS-2 to show our progress towards the Portfolio Level Standards in each Portfolio Coversheet. Portfolio 0, as reflected in Progress Report 0, meets both the Portfolio Level Ignition Decrease Standard and the Portfolio Level Reliability Increase Standard. However, neither of the System Level Standards are currently being met. The System Level metrics are normalized across total system miles, therefore, as the Portfolio expands, the gap to meeting the System Level Standards is expected to decrease.

TABLE PCS-2:
PORTFOLIO STANDARDS

Line No.	Standard	Value	Portfolio 0
1	Ignition Risk Decrease Standard at Portfolio Level	$0.045M/mile	$0.057M/mile
2	Reliability Increase Standard at Portfolio Level	$0.100M/mile	$0.236M/mile
3	Ignition Risk Decrease Standard at System Level	$0.0023M/mile	$0.0001M/mile
4	Reliability Increase Standard at System Level	$0.0049M/mile	$0.0005M/mile

3. Exclusion of Circuit Segments in Top 5 Percent of Overall Utility Risk

PG&E interprets the term "exclusion" in this prompt to mean the affirmative removal of a Circuit Segment from consideration after it has been determined eligible for progression beyond Screen 1. Circuit Segments that do not satisfy Screen 1 eligibility criteria are considered ineligible rather than excluded. The process for reviewing and potentially excluding Circuit Segments from EUP consideration during the screening process is

discussed in Chapter 3 Section D. PG&E uses the WDRM v4 for our mitigation selection and decision-making. PG&E does not use Overall Utility Risk scores as a criterion to select Projects.

The total number of Circuit Segments that make up the top 5 percent of Overall Utility Risk is 186. As of the date of this filing, none of the 186 Circuit Segments has been excluded from PG&E's EUP. Excluded Circuit Segments in the top 5 percent of Overall Utility Risk, when identified, will be listed in Table PCS-3 in the Portfolio Coversheet (Attach. A-1).

4. Instantaneous and Cumulative Risk Scores for Each KDMM

The KDMMs are non-financial measures a utility uses to measure how effective an Undergrounding Project will be at reducing Wildfire Risk. They reflect real-world, observable risk conditions and are not shaped by financial factors or risk preferences. These metrics can be applied at three scales: (1) systemwide, (2) across a Portfolio of Circuit Segments, or (3) for a single project—to show how much risk is concentrated or reduced at each level. PG&E's KDMMs are discussed in PG&E's EUP Chapter 7, Section E.

Tables PCS-4 and PCS-5 show the instantaneous risk scores and cumulative risk scores for each KDMM. These scores demonstrate how much Ignition Risk, Outage Program Risk, and Overall Utility Risk is expected to decrease as the Portfolio is constructed. All numbers are shown in 2028 dollars. Tables PCS-4 and PCS-5 will be updated in the Portfolio Coversheet as the EUP progresses.

TABLE PCS-4:
INSTANTANEOUS RISK SCORES FOR EACH KDMM

Line No.	Year	OUR ~~(2028, $~~($M)	Ignition			Outage		
			Risk ~~(2028, $~~($M)	Likelihood (Expected Ignitions per Year)	Conseq. ~~(2028, $~~($M)	Risk ~~(2028, $~~($M)	Likelihood (Expected Minutes per Year)	Conseq. ~~(2028, $~~($M)
1	0	$61.982	$14.163	~~0.029~~ 1.006	~~$492.776~~ $14.084	$47.819	~~629.762~~57,031	~~$0.076~~ $0.0008
2	1	~~$0.676~~ $2.696	~~$0.676~~ $2.250	~~0.001~~ 0.086	~~$492.776~~ $26.251	$0.~~000~~446	0.~~000~~1,209	~~$0.076~~ $0.0004
3	2	~~$0.682~~ $0.692	~~$0.682~~ $0.692	~~0.001~~ 0.056	~~$492.776~~ $12.321	$0.000	0.000	~~$0.076~~ $0.0000
4	3	~~$0.682~~ $0.713	~~$0.682~~ $0.713	~~0.001~~ 0.056	~~$492.776~~ $12.699	$0.000	0.000	~~$0.076~~ $0.0000
5	4	~~$0.682~~ $0.729	~~$0.682~~ $0.729	~~0.001~~ 0.056	~~$492.776~~ $12.989	$0.000	0.000	~~$0.076~~ $0.0000
6	5	~~$0.682~~ $0.746	~~$0.682~~ $0.746	~~0.001~~ 0.056	~~$492.776~~ $13.286	$0.000	0.000	~~$0.076~~ $0.0000
7	6	~~$0.682~~ $0.763	~~$0.682~~ $0.763	~~0.001~~ 0.056	~~$492.776~~ $13.589	$0.000	0.000	~~$0.076~~ $0.0000
8	7	~~$0.682~~ $0.780	~~$0.682~~ $0.780	~~0.001~~ 0.056	~~$492.776~~ $13.898	$0.000	0.000	~~$0.076~~ $0.0000
9	8	~~$0.682~~ $0.798	~~$0.682~~ $0.798	~~0.001~~ 0.056	~~$492.776~~ $14.215	$0.000	0.000	~~$0.076~~ $0.0000
10	9	~~$0.681~~ $0.816	~~$0.681~~ $0.816	~~0.001~~ 0.056	~~$492.776~~ $14.539	$0.000	0.000	~~$0.076~~ $0.0000
11	10	~~$0.681~~ $0.835	~~$0.681~~ $0.835	~~0.001~~ 0.056	~~$492.776~~ $14.870	$0.000	0.000	~~$0.076~~ $0.0000
12	15	~~$0.681~~ $0.955	~~$0.681~~ $0.955	~~0.001~~ 0.056	~~$492.776~~ $17.016	$0.000	0.000	~~$0.076~~ $0.0000
13	20	~~$0.681~~ $1.069	~~$0.681~~ $1.069	~~0.001~~ 0.056	~~$492.776~~ $19.033	$0.000	0.000	~~$0.076~~ $0.0000
14	25	~~$0.695~~ $1.221	~~$0.695~~ $1.221	~~0.001~~ 0.056	~~$492.776~~ $21.756	$0.000	0.000	~~$0.076~~ $0.0000
15	30	~~$0.720~~ $1.416	~~$0.720~~ $1.416	~~0.001~~ 0.056	~~$492.776~~ $25.217	$0.000	0.000	~~$0.076~~ $0.0000

Line No.	Year	OUR (2028, $($M)	Ignition			Outage		
			Risk (2028, $($M)	Likelihood (Expected Ignitions per Year)	Conseq. (2028, $($M)	Risk (2028, $($M)	Likelihood (Expected Minutes per Year)	Conseq. (2028, $($M)
16	35	~~$0.745~~ $1.640	~~$0.745~~ $1.640	~~0.002~~ 0.056	~~$492.776~~ $29.207	$0.000	0.000	~~$0.076~~ $0.0000
17	40	~~$0.770~~ $1.898	~~$0.770~~ $1.898	~~0.002~~ 0.056	~~$492.776~~ $33.804	$0.000	0.000	~~$0.076~~ $0.0000
18	45	~~$0.796~~ $2.195	~~$0.796~~ $2.195	~~0.002~~ 0.056	~~$492.776~~ $39.099	$0.000	0.000	~~$0.076~~ $0.0000
19	50	~~$0.822~~ $2.537	~~$0.822~~ $2.537	~~0.002~~ 0.056	~~$492.776~~ $45.194	$0.000	0.000	~~$0.076~~ $0.0000
20	55	~~$0.848~~ $2.931	~~$0.848~~ $2.931	~~0.002~~ 0.056	~~$492.776~~ $52.206	$0.000	0.000	~~$0.076~~ $0.0000

Note: These values currently reflect Projects slated for 2028 in the UG workplan. As additional progress reports are issued, the table will be updated to account for the additional Projects (i.e., the 2028 year 0 will not change as there will not be additional Projects for 2028; however, year 1 will see an increase in all the values as the Projects for 2029 finish with scoping their values will get populated for years 1 onwards).

TABLE PCS-5:
CUMULATIVE RISK SCORES FOR EACH KDMM

Line No.	Year	OUR ~~(2028, $($M)~~	Ignition			Outage		
			Risk ~~(2028, $($M)~~	Likelihood (Expected Ignitions)	Conseq. ~~(2028, $($M)~~	Risk ~~(2028, $($M)~~	Likelihood (Expected Minutes)	Conseq. ~~(2028, $($M)~~
1	0	$61.982	$14.163	~~0.029~~ 1.006	~~$492.776~~ $14.084	$47.819	~~629.762~~ 57,031	~~$0.076~~ $0.000838
2	1	~~$1.347~~ $64.678	~~$1.347~~ $16.413	~~0.003~~ 1.091	~~$492.776~~ $15.039	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
3	2	~~$2.029~~ $65.370	~~$2.029~~ $17.105	~~0.004~~ 1.147	~~$492.776~~ $14.906	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
4	3	~~$2.710~~ $66.083	~~$2.710~~ $17.818	~~0.006~~ 1.204	~~$492.776~~ $14.804	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
5	4	~~$3.392~~ $66.812	~~$3.392~~ $18.547	~~0.007~~ 1.260	~~$492.776~~ $14.723	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
6	5	~~$4.073~~ $67.558	~~$4.073~~ $19.293	~~0.008~~ 1.316	~~$492.776~~ $14.661	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
7	6	~~$4.755~~ $68.320	~~$4.755~~ $20.056	~~0.010~~ 1.372	~~$492.776~~ $14.617	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
8	7	~~$5.437~~ $69.101	~~$5.437~~ $20.836	~~0.011~~ 1.428	~~$492.776~~ $14.589	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
9	8	~~$6.118~~ $69.899	~~$6.118~~ $21.634	~~0.012~~ 1.484	~~$492.776~~ $14.575	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
10	9	~~$6.800~~ $70.715	~~$6.800~~ $22.450	~~0.014~~ 1.540	~~$492.776~~ $14.574	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
11	10	~~$7.481~~ $71.550	~~$7.481~~ $23.285	~~0.015~~ 1.597	~~$492.776~~ $14.584	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
12	15	~~$10.887~~ $76.972	~~$10.887~~ $28.707	~~0.022~~ 1.933	~~$492.776~~ $14.848	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
13	20	~~$14.292~~ $82.083	~~$14.292~~ $33.818	~~0.029~~ 2.214	~~$492.776~~ $15.274	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
14	25	~~$17.724~~ $87.851	~~$17.724~~ $39.587	~~0.036~~ 2.495	~~$492.776~~ $15.868	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829

Line No.	Year	OUR ~~(2028, $~~($M)	Ignition			Outage		
			Risk ~~(2028, $~~($M)	Likelihood (Expected Ignitions)	Conseq. ~~(2028, $~~($M)	Risk ~~(2028, $~~($M)	Likelihood (Expected Minutes)	Conseq. ~~(2028, $~~($M)
15	30	~~$21.273~~ $94.530	~~$21.273~~ $46.265	~~0.043~~ 2.776	~~$492.776~~ $16.669	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
16	35	~~$24.948~~ $102.268	~~$24.948~~ $54.003	~~0.051~~ 3.056	~~$492.776~~ $17.670	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
17	40	~~$28.748~~ $111.225	~~$28.748~~ $62.961	~~0.058~~ 3.337	~~$492.776~~ $18.868	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
18	45	~~$32.676~~ $121.589	~~$32.676~~ $73.324	~~0.066~~ 3.618	~~$492.776~~ $20.269	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
19	50	~~$36.733~~ $133.571	~~$36.733~~ $85.306	~~0.075~~ 3.898	~~$492.776~~ $21.883	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829
20	55	~~$40.921~~ $147.416	~~$40.921~~ $99.151	~~0.083~~ 4.179	~~$492.776~~ $23.726	~~$0.000~~ $48.265	~~0.000~~ 58,240	~~$0.076~~ $0.000829

Note: These values currently reflect Projects slated for 2028 in the UG workplan. As additional Progress Reports are issued, the table will be updated to account for the additional Projects (i.e., the 2028 year 0 will not change as there will not be additional Projects for 2028; however, year 1 will see an increase in all the values as the Projects for 2029 finish with scoping their values will get populated for years 1 onwards).

We describe the KDMMs and provide formulas showing how each KDMM is aggregated to the system and portfolio level in Chapter 7, Section E. (See also Attach. B, WP021 (KDMM Formulas).) We describe the discount rates and climate change assumptions used in the KDMM calculations in Chapter 7, Section G.4, Core Capability 4.

F. System and Portfolio-Level Risk Matrices and Profiles for Key Decision-Making Metrics (EUP Guidelines Section 2.8.6.2)

The EUP must include a series of visualizations and tables for each of the KDMMs showing the KDMM's distribution both with and without the Portfolio's modeled mitigation. These visualizations will be included in the Portfolio Coversheet.

On the Portfolio Coversheet, each KDMM's distribution must be reported on both a system wide and Portfolio wide scale and emphasize the position of projects within the Risk Landscape. Every figure and table on the Portfolio Coversheet must include a caption explaining the figure.

Risk scores, the product of likelihood and consequence, must be reported as two-dimensional risk matrices. Risk scores can be weighted if appropriate. Two examples of risk score matrices for Ignition Risk are presented below (Figures 3 6), followed by another example of a risk score matrix for Outage Program Risk (Figures 7 10).

The Ignition Consequence Profile must indicate the Large Electrical Corporation's Ignition Tail Risk Threshold. Outage Program Likelihood and Outage Program Consequence must be reported similarly to Ignition Likelihood and Ignition Consequence. The System Outage Program Likelihood Profile must indicate the Large Electrical Corporation's High Frequency Outage Program Threshold and High Frequency Outage Program Project Level Standard.

The Large Electrical Corporation must report other KDMMs similarly. The visualizations must demonstrate the distribution of the metric over the entire system and within the scope of the Portfolio separately. Additionally, the visualizations must illustrate the Large Electrical Corporation's approximation of its risk profile both before and after the proposed mitigations. Note that these visualizations are not meant to be a comprehensive examination of the EUP, but rather a summary of the most critical metrics.

The Large Electrical Corporation must indicate how it computes the integration, summation, quadrature, or likelihood estimation used to compute this accumulation in its definition of these terms (See Section 2.7.6 of these Guidelines for more details).

This discussion will include any discount rates, risk attitude weights or other user parameters used to model the accumulation of risk over time.

Each of these metrics must be reported for both the Baseline regime and the Portfolio at the System Level and Portfolio Level as detailed in Appendices C.1 and C.2.

Our Portfolio Coversheet contains tables and visualizations for each KDMM showing the KDMM's distribution both with and without the Portfolio's modeled mitigation at both the System-wide and Portfolio-wide scale, emphasizing the Projects within the risk landscape. The visualizations demonstrate the distribution of the KDMM over the entire system and within the scope of the Portfolio separately. Additionally, the visualizations illustrate PG&E's risk profile both before and after the proposed mitigations.

The required KDMM tables and visualizations, the instantaneous and cumulative risk score tables, and the Project Variable Multiplier table are included in the Portfolio Coversheet in Section C. The KDMM tables and visualizations comply with the template and format presented in the EUP Guidelines. PG&E notes that some readers may find these tables and visualizations difficult to interpret, and further, may have difficulty discerning the post-mitigation benefits of the EUP, given the color coding and scaling used. PG&E may update the format of these tables and visualizations for readability in subsequent Progress Reports, based on Energy Safety feedback.

The Portfolio, illustrated in Figures PCS-3 to PCS-12 below, is based on high-level cost and scope assumptions consistent with Screen 2 requirements. The Undergrounding Projects in this Portfolio are subject to change as assumptions are refined through the detailed scoping and risk evaluation in Screen 3 and represent an approximation of pre- and post-mitigated KDMMs based on available information.

The primary goal of the KDMMs figures below is to demonstrate that likelihood decreases following mitigation actions. This reduction is evident in the High-Risk, Tail Risk, and High-Frequency outage program Circuit Segment points. Post-mitigation likelihood for each Circuit Segment is calculated as:

$$\boldsymbol{Formula}: Mitigation\ Liklehood = Unmitigated\ Likelihood * (1 - Effective\ Mitigation\ Fraction)$$

The Effective Mitigation Fraction represents the proportion of HFTD/HFRA overhead line mileage within the Circuit Segment that is treated, weighted by the mitigation-effectiveness of each treatment type, including undergrounding and overhead hardening. Circuit Segments that are moved underground and/or are overhead hardened are assigned proportional mitigation credit based on the

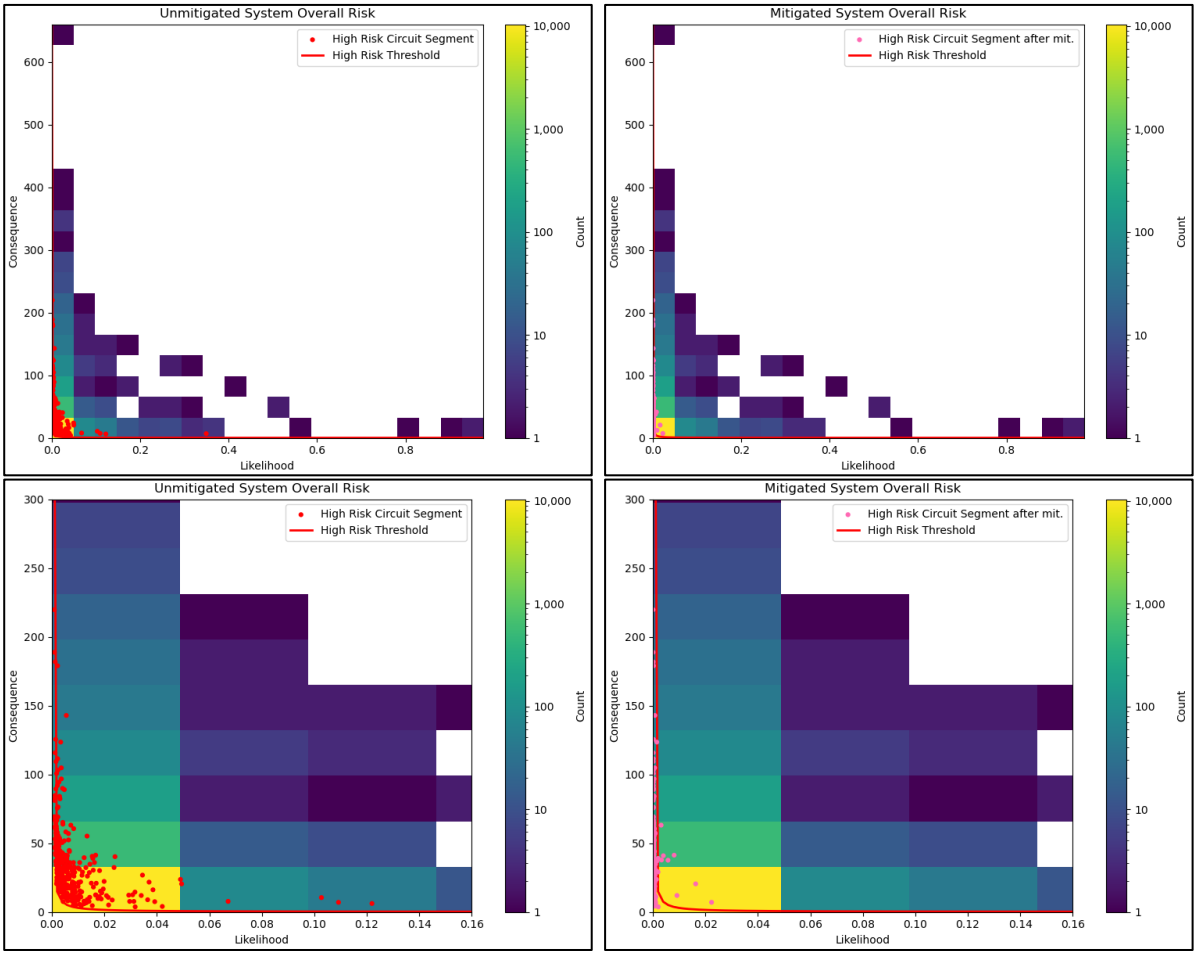
fraction of treated mileage relative to the total HFTD/HFRA overhead mileage within that segment. Consequence is assumed to remain unchanged by mitigation, with only likelihood being reduced.

1. Overall Utility Risk (System)

Figure PCS-3 below (based on EUP Example Figure 3)[204] demonstrates the substantial improvement in Overall Utility Risk expected from the EUP, using Overall Utility Risk as a KDMM. Each figure plots Adverse Event Consequence on the y-axis (arbitrary units) against Adverse Event Likelihood on the x-axis (arbitrary units), incorporating both Outage Program Risk and Ignition Risk. Due to the Outage Program Risk and Ignition Risk using fundamentally different likelihood scales (outage-minutes/year vs ignitions/year), neither likelihood nor consequence can be expressed in a single standard unit. To produce a unified visual, we normalize each component likelihood to a 0-1 scale, then compute a risk-weighted average that reflects each component's share of total segment risk. Consequence is back-calculated via Consequence = Risk/Likelihood. Likelihood and Consequence are provided per mile, to allow project risk to be ranked without being skewed by high-risk/high-mileage Projects. While the individual axes do not carry direct physical units, the relative positioning of segments represents their comparative risk profiles, and the underlying dollar-denominated risk values are preserved in the product of the two axes. The background heatmap represents the modeled distribution of Circuit Segments across the system. The red diagonal line represents the High-Risk Threshold used to identify candidate segments for undergrounding.

204 PG&E is following the table numbering for the Portfolio Coversheet tables in the Guidelines, which starts at Figure 3. (Figures 1 and 2 are in other areas of the narrative.) Therefore there is no table labeled PCS-1 in this chapter or in the Portfolio Coversheet.

FIGURE PCS-3:
RISK SCORE MATRIX DEMONSTRATING SUBSTANTIAL IMPROVEMENTS IN OVERALL UTILITY RISK EXPECTED DUE TO EUP

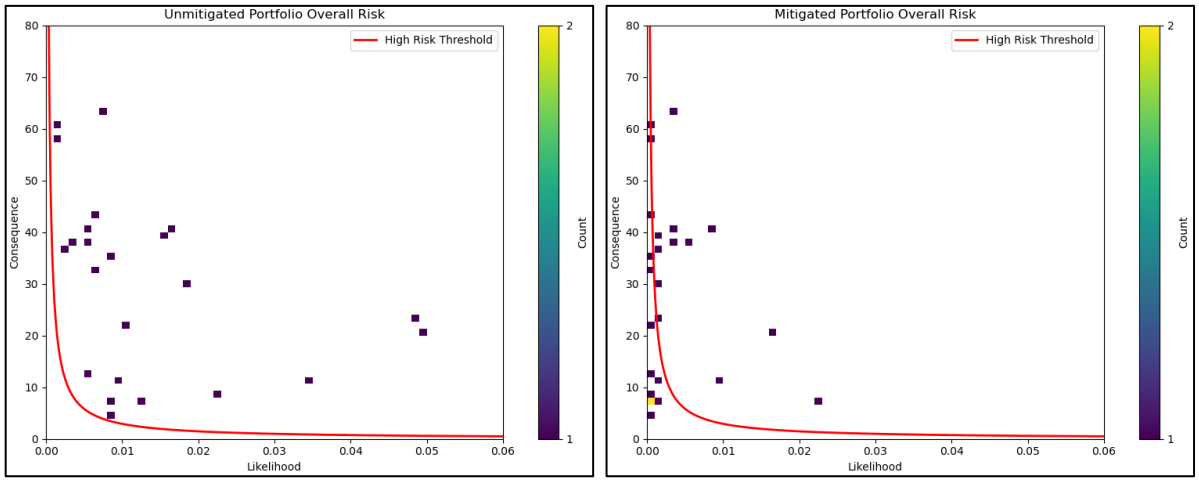


- Left (upper): Modeled system conditions prior to implementation of EUP mitigations. Red points represent Circuit Segments selected for undergrounding because they exceed the High-Risk Threshold.
- Right (upper): Modeled system conditions after undergrounding is applied to the selected segments. The heatmap reflects the modeled reduction in likelihood associated with undergrounding. Pink points represent the same selected Circuit Segments after mitigation.
- Left (lower): Zoomed view of pre-mitigation conditions, focused on high- risk Circuit Segments to highlight their position above the High-Risk Threshold.
- Right (lower): Zoomed view of post-mitigation conditions for the same Circuit Segments, illustrating their transition after mitigation relative to the High-Risk Threshold.

2. Overall Utility Risk (Portfolio)

Figure PCS-4 below (based on EUP Example Figure 4) displays only the EUP Portfolio, rather than the entire system Overall Utility Risk.

FIGURE PCS-4:
RISK SCORE MATRIX FOR PORTFOLIO LEVEL OVERALL UTILITY RISK

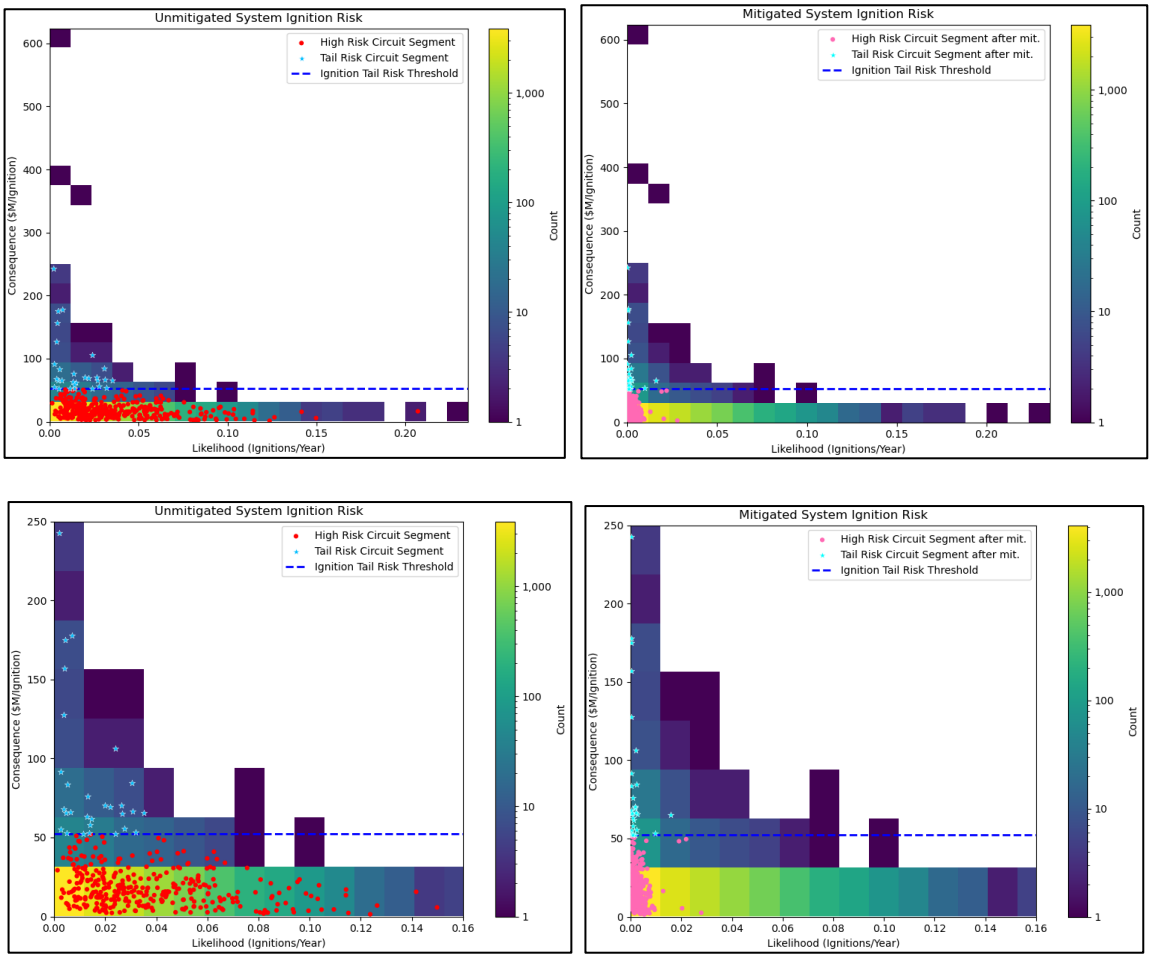


- Left: Portfolio risk distribution prior to mitigation.
- Right: Portfolio risk distribution after undergrounding mitigations are applied.

3. Ignition Risk (System)

Figure PCS-5 below (based on EUP Example Figure 5) demonstrates the substantial improvement in Ignition Risk expected due to the EUP. Each figure plots Ignition Consequence on the y-axis (arbitrary units) and Ignition Likelihood on the x-axis (arbitrary units). The background heatmap shows the modeled system distribution, with the Ignition Tail Risk Threshold shown as a blue dotted line.

FIGURE PCS-5:
RISK SCORE DEMONSTRATION OF SUBSTANTIAL IMPROVEMENTS IN IGNITION RISK



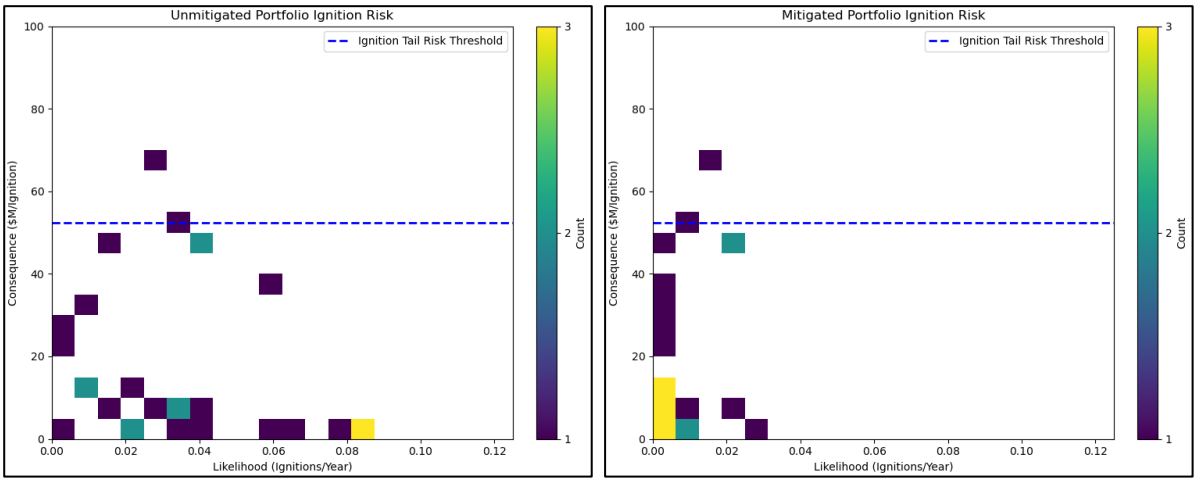
- <u>Left (upper):</u> Modeled system conditions prior to EUP mitigations. Red points represent Circuit Segments selected for undergrounding based on exceeding the High-Risk Threshold. Blue stars represent Circuit Segments selected for exceeding the Ignition Tail Risk Threshold.

- Right (upper): Modeled system conditions after undergrounding. The heatmap reflects reduced likelihood for mitigated segments. Pink points and teal stars represent the same High-Risk and Tail Risk Circuit Segments, respectively, after mitigation.
- Left (lower): Zoomed view of pre-mitigation conditions, focused on High-Risk and Tail Risk Circuit Segments to highlight their position relative to the Ignition Tail Risk Threshold.
- Right (lower): Zoomed view of post-mitigation conditions for the same Circuit Segments, illustrating their transition after mitigation relative to the Ignition Tail Risk Threshold.

4. Ignition Risk (Portfolio)

Figure PCS-6 below (based on EUP Example Figure 6) displays the EUP Portfolio risk rather than the full system risk.

FIGURE PCS-6:
RISK SCORE MATRIX FOR PORTFOLIO LEVEL IGNITION RISK

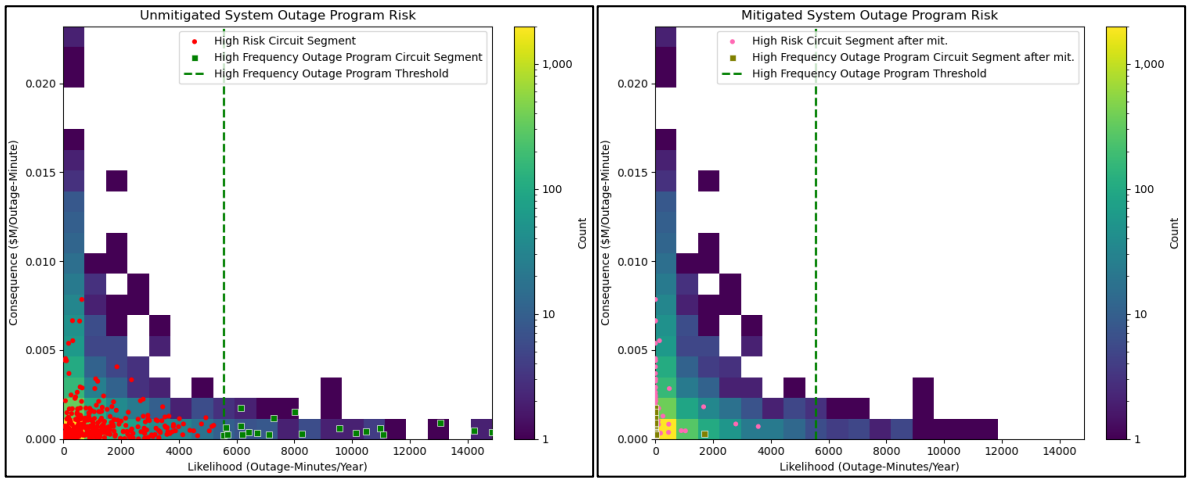


- Left: Portfolio risk distribution prior to mitigation.
- Right: Portfolio risk distribution after mitigation.

5. Outage Program Risk (System)

Figure PCS-7 below (based on EUP Example Figure 7) demonstrates the substantial improvement in Outage Program Risk expected from the EUP. Each figure plots Outage Program Consequence on the y-axis (arbitrary units) and Outage Program Likelihood on the x-axis (arbitrary units). The background heatmap represents the modeled system distribution. The High-Frequency Outage Program Threshold is shown as a green dotted line.

FIGURE PCS-7:
RISK SCORE MATRIX FOR DEMONSTRATION OF SUBSTANTIAL IMPROVEMENT IN OUTAGE PROGRAM RISK

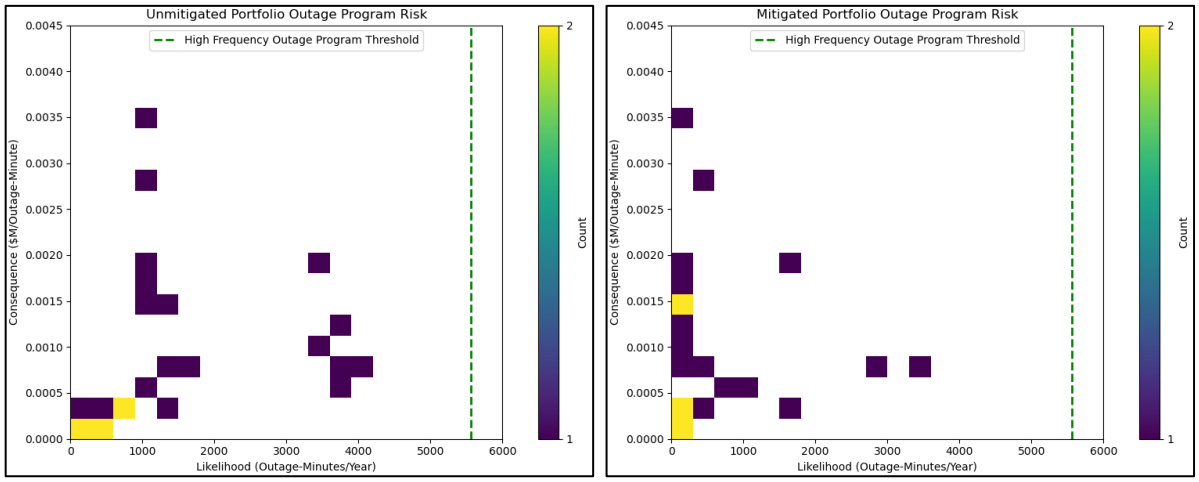


- Left: Modeled system conditions prior to EUP mitigations. Red points represent Circuit Segments selected for undergrounding due to exceeding the High-Risk Threshold. Green squares represent Circuit Segments exceeding the High-Frequency Outage Program Threshold.
- Right: Modeled system conditions after undergrounding. The heatmap reflects reduced likelihood. Pink points and olive squares represent the same High-Risk and High-Frequency Outage Circuit Segments, respectively, after mitigation. The post-mitigation Circuit Segment points are tightly clustered near zero, making them difficult to distinguish individually in the visualization.

6. Outage Program Risk (Portfolio)

Figure PCS-8 below (based on EUP Example Figure 8) displays only the EUP Portfolio.

FIGURE PCS-8:
RISK MATRIX FOR PORTFOLIO LEVEL OUTAGE PROGRAM RISK

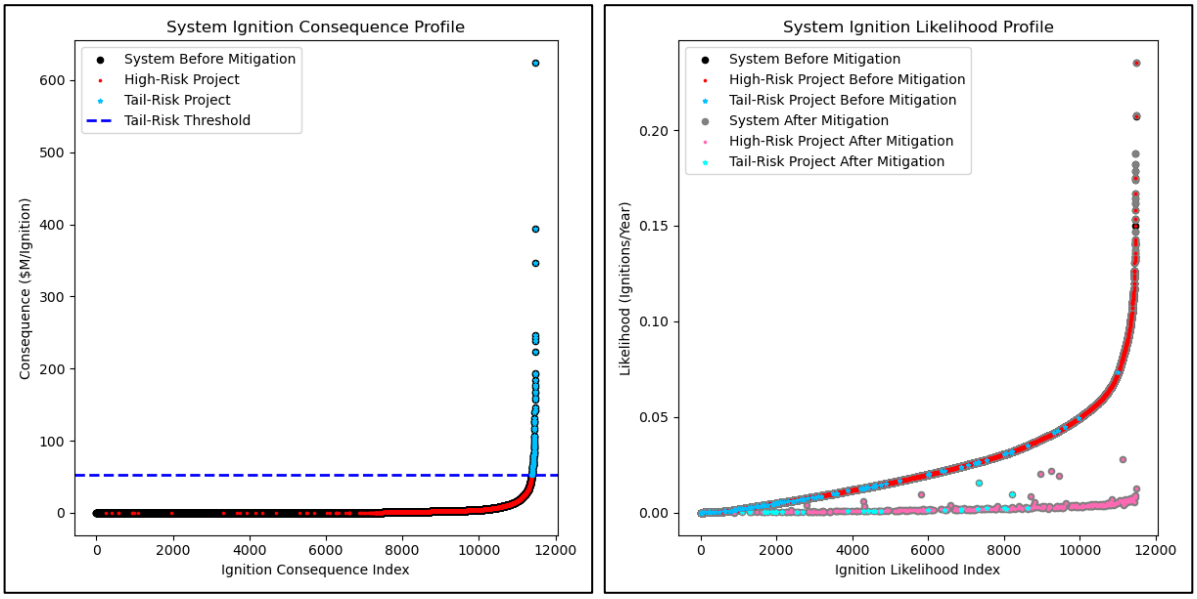


- Left: Portfolio risk distribution prior to mitigation.
- Right: Portfolio risk distribution after mitigation.

7. Ignition Consequence and Likelihood (System)

Figure PCS-9 below (based on EUP Example Figure 9) presents Ignition Consequence and Ignition Likelihood profiles for Circuit Segments selected using Ignition Risk and wildfire consequence as KDMMs.

FIGURE PCS-9:
IGNITION CONSEQUENCE AND LIKELIHOOD PROFILES

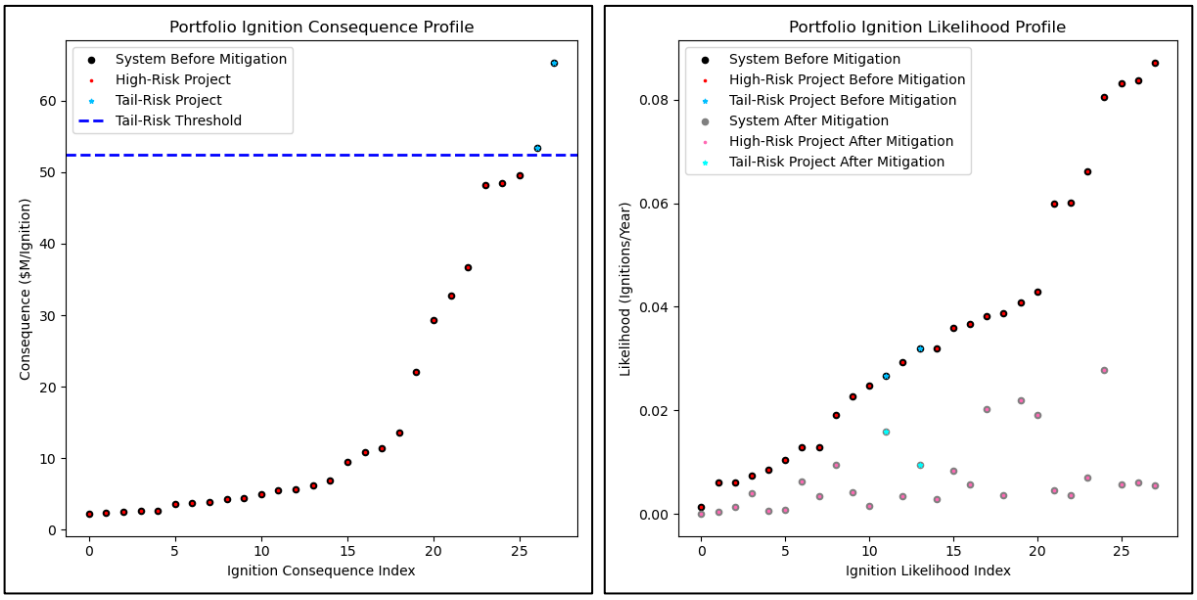


- Left: All Circuit Segments ordered from lowest to highest Ignition Consequence, with consequence scores shown on the y-axis (arbitrary units). The blue line represents the Ignition Tail Risk Threshold. Blue stars indicate Circuit Segments exceeding this threshold. Red dots represent high-risk Circuit Segments selected based on overall Ignition Risk. Since undergrounding affects likelihood, but not consequence, this panel is unchanged by mitigation.
- Right: All Circuit Segments ordered from lowest to highest Ignition Likelihood. Red points and blue stars correspond to the same Circuit Segments shown in the left panel. Grey points show the modeled system after mitigation, with pink points and cyan stars representing undergrounded high-risk and tail risk Circuit Segments, respectively.

8. Ignition Consequence and Likelihood (Portfolio)

Figure PCS-10 below presents Ignition Consequence and Ignition Likelihood profiles for Circuit Segments in the EUP Portfolio.

FIGURE PCS-10:
PORTFOLIO IGNITION CONSEQUENCE AND LIKELIHOOD PROFILES

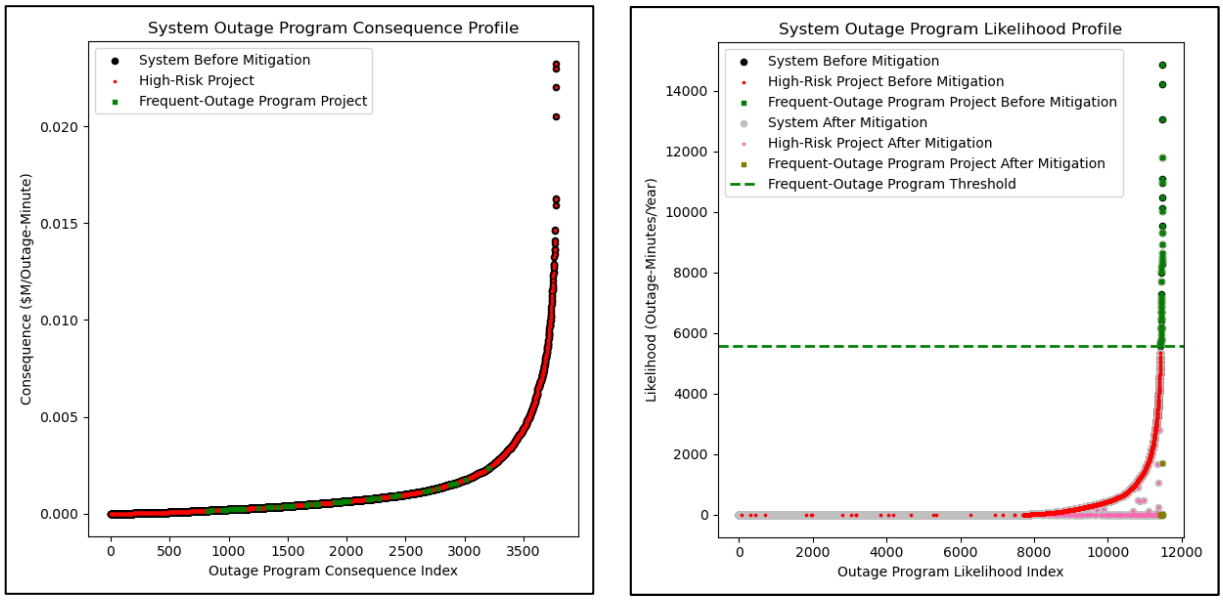


- Left: Portfolio Ignition Consequence.
- Right: Portfolio Ignition Likelihood.

9. Outage Program Consequence and Likelihood (System)

Figure PCS-11 below (based on Example Figure 10) presents Outage Program Consequence and Likelihood profiles for Circuit Segments selected using Outage Program Risk and Outage Program Consequence as KDMMs.

FIGURE PCS 11:
OUTAGE PROGRAM CONSEQUENCE AND LIKELIHOOD PROFILES

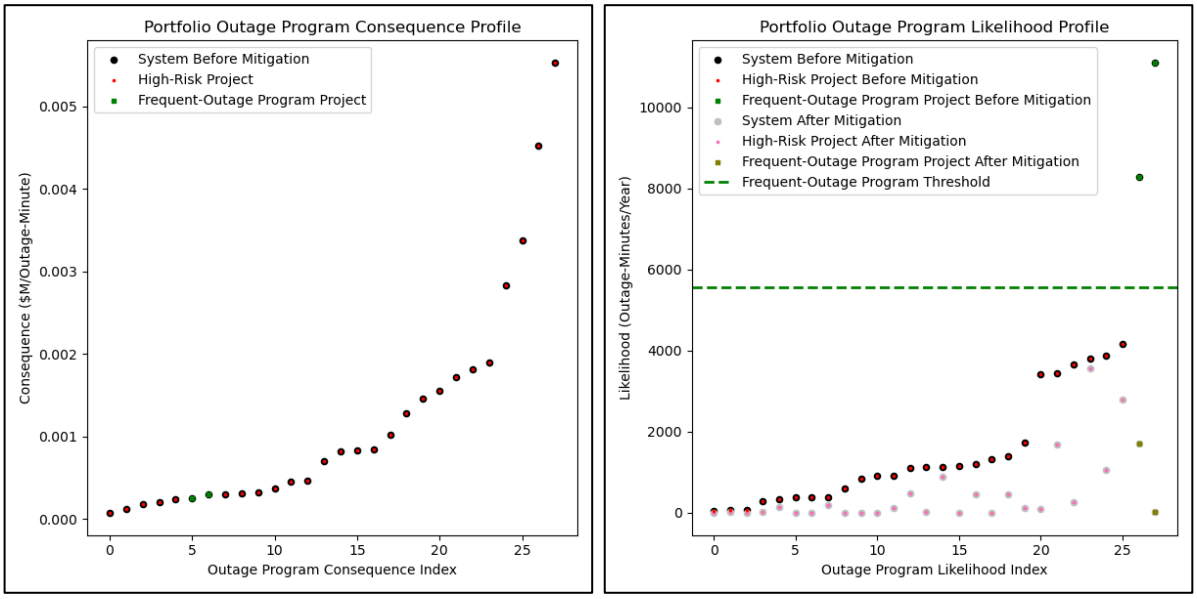


- Left: All Circuit Segments ordered from lowest to highest Outage Program Consequence, with consequence scores shown on the y-axis (arbitrary units). Green squares indicate Circuit Segments selected for undergrounding because their Outage Program Likelihood exceeds the High-Frequency Outage Program Threshold. Red dots represent high-risk Circuit Segments selected based on overall Outage Program Risk. Since undergrounding affects likelihood, but not consequence, this panel is unchanged by mitigation.
- Right: All Circuit Segments ordered from lowest to highest Outage Program Likelihood. The green line represents the High-Frequency Outage Program Threshold. Green squares indicate pre-mitigation exceedances, and olive squares represent the same segments after mitigation. Grey points show the modeled system after mitigation, with pink points and olive stars highlighting undergrounded high-risk and high-frequency outage Circuit Segments.

10. Outage Program Consequence and Likelihood (Portfolio)

Figure PCS-12 below presents Outage Program Consequence and Outage Program Likelihood profiles for Circuit Segments in the EUP Portfolio.

FIGURE PCS-12:
PORTFOLIO OUTAGE PROGRAM CONSEQUENCE AND LIKELIHOOD PROFILES



- Left: Portfolio Outage Program Consequence.
- Right: Portfolio Outage Program Likelihood.

G. Portfolio Development (EUP Guidelines Section 2.8.6.3)

The Large Electrical Corporation must detail its system for tracking changes in the Portfolio of Undergrounding Projects over time, as well as the consistency of its modeling updates.

The Large Electrical Corporation must track how its Portfolio of Undergrounding Projects has changed over the duration of the EUP by applying the most up to date modeling system version and calibration to each of the historical Portfolios considered during the lifetime of the EUP.

The Large Electrical Corporation must summarize this information in each Progress Report, including Progress Report 0, by creating two plots for each KDMM showing their mean value and first standard variation, measured over the total Portfolio footprint. The total Portfolio footprint is defined as the union of all Circuit Segments included in any Portfolio.

The first plot must show the instantaneous value of the KDMM after the EUP has been completed, as measured by the most recent version and calibration of Risk Modeling Methodology, compared to the Baseline at the beginning of the plan, as measured by the most recent version of the Risk Modeling Methodology.

The second plot must show the same metrics but measured by the version of the Risk Modeling Methodology that was most recent at the time the Portfolio was updated.

We will show how the Portfolio changes over the life of the EUP by creating two plots for each KDMM, showing their mean value and first standard deviation, as measured over the total Portfolio. This information is included on the Coversheet of Progress Report 0 and will be updated and included in each subsequent Progress Report.

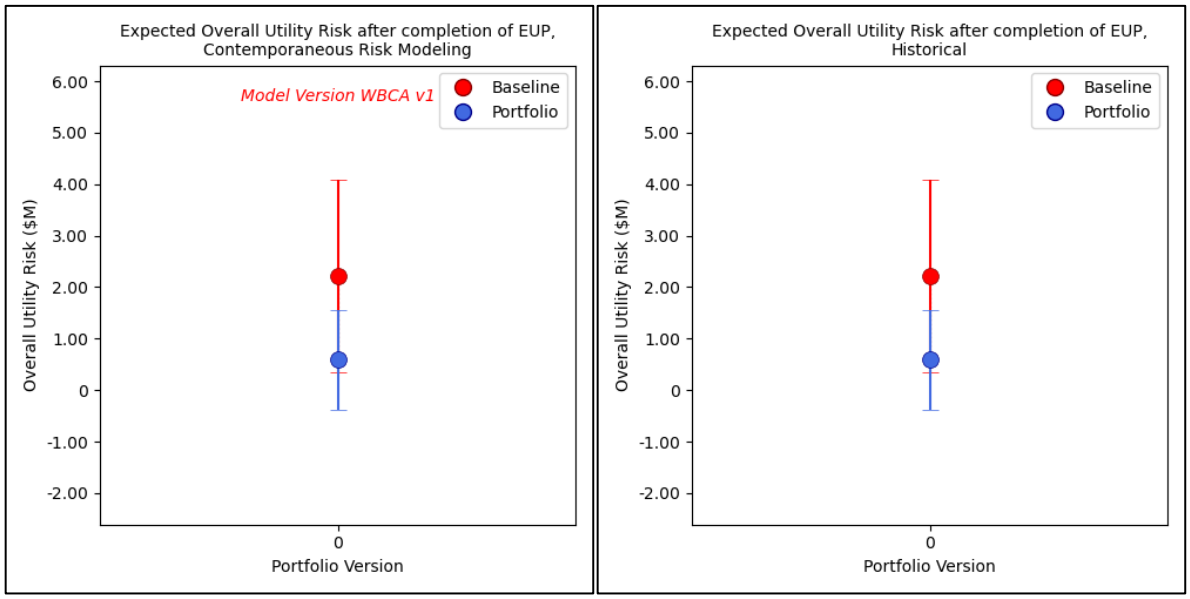
Figures PCS-13A through PCS-13E below (based on EUP Example Figure 11) present KDMM plots showing the mean value and first standard deviation, measured over the total Portfolio. Note that, due to EUP Guideline requirements for the figures below, the distributions are skewed; therefore, the mean and standard deviation are not representative of the distribution's center and spread.

Because Progress Report 0 is the initial report, only a single data point is represented in the figures below. As subsequent Progress Reports are filed, and additional data is plotted over time, the changes to the Portfolio of Undergrounding Projects will be observable. These figures are also included in the Portfolio Coversheet.

1. Overall Utility Risk

Figure PCS-13A will illustrate the reductions in Overall Utility Risk as we implement Portfolio 0.

FIGURE PCS-13A:
KDMM DEVELOPMENT: CHANGES IN PORTFOLIO OVERALL UTILITY RISK

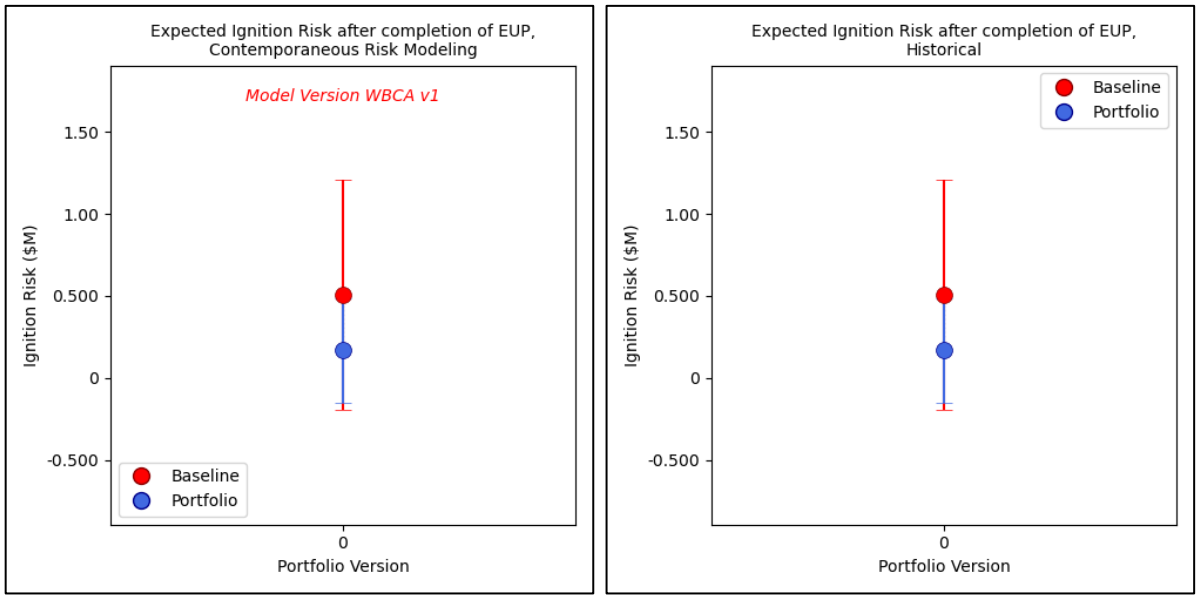


- Left: A plot showing the mean and standard deviation of the Overall Utility Risk Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using the most recent version of the model, WBCA v1. The x-axis denotes the version of the Portfolio.
- Right: A plot showing the mean and standard deviation of the Overall Utility Risk Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using WBCA v1, which was the most recent version of this model when the Portfolio was updated.

2. Ignition Risk

Figure PCS-13B will demonstrate reductions to system Ignition Risk following implementation of Portfolio 0.

FIGURE PCS-13B:
KDMM DEVELOPMENT: CHANGES IN PORTFOLIO IGNITION RISK



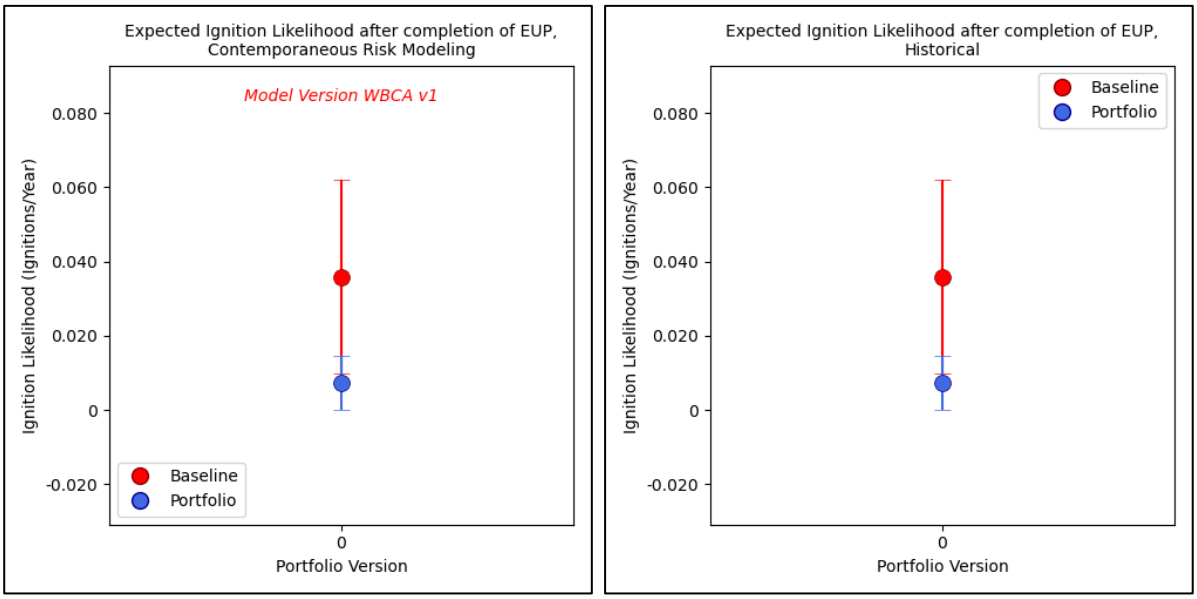
- Left: A plot showing the mean and standard deviation of the Ignition Risk's Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using the most recent version of the model, WBCA v1. The x-axis denotes a different version of the Portfolio.
- Right: A plot showing the mean and standard deviation of the Ignition Risk's Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using the WBCA v1, which was most recent at the time the Portfolio was updated.

3. Ignition Consequence and Likelihood

KDMM graphs are not produced for Ignition Consequence, as EUP mitigation minimally modifies the consequence of an ignition, thus the modeled value after EUP mitigation is unchanged.

Figure PCS-13C will indicate that the system's Ignition Likelihood declines with the implementation of Portfolio 0.

FIGURE PCS-13C:
KDMM DEVELOPMENT: CHANGES IN PORTFOLIO IGNITION LIKELIHOOD

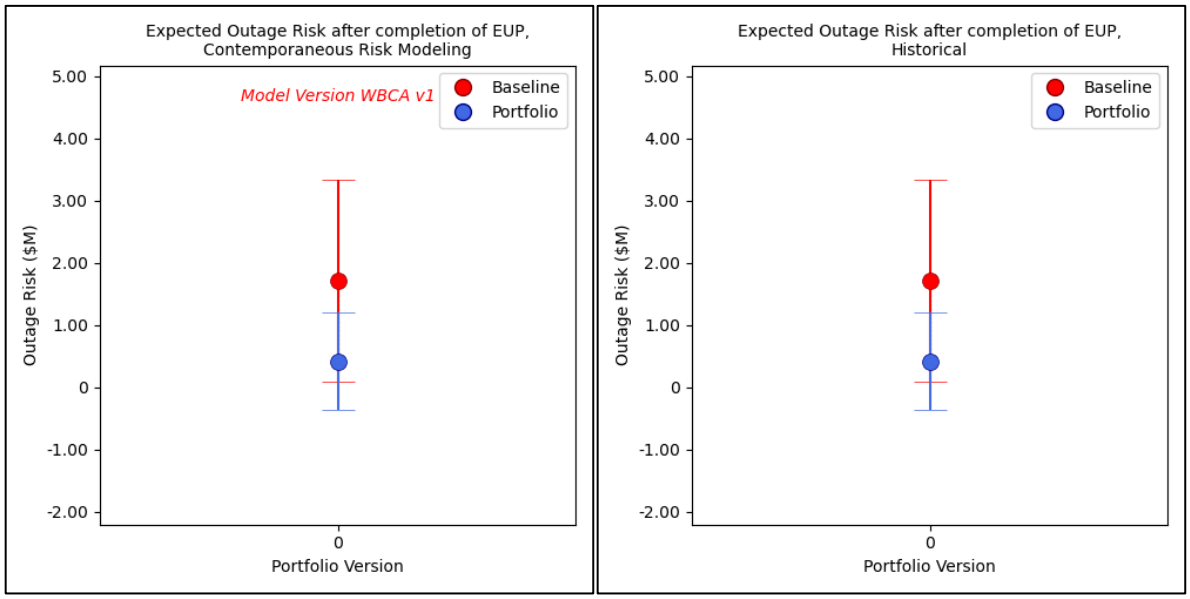


- Left: A plot showing the mean and standard deviation of the Ignition Likelihood's Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using the most recent version of the model, WBCA v1. The x-axis denotes a different version of the Portfolio.
- Right: A plot showing the mean and standard deviation of the Ignition Likelihood's Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using the WBCA v1, which was most recent at the time the Portfolio was updated.

4. Outage Program Risk

Figure PCS-13D shows a decrease in the system's Outage Program Risk associated with implementation of Portfolio 0.

FIGURE PCS-13D:
KDMM DEVELOPMENT: CHANGES IN PORTFOLIO OUTAGE PROGRAM RISK



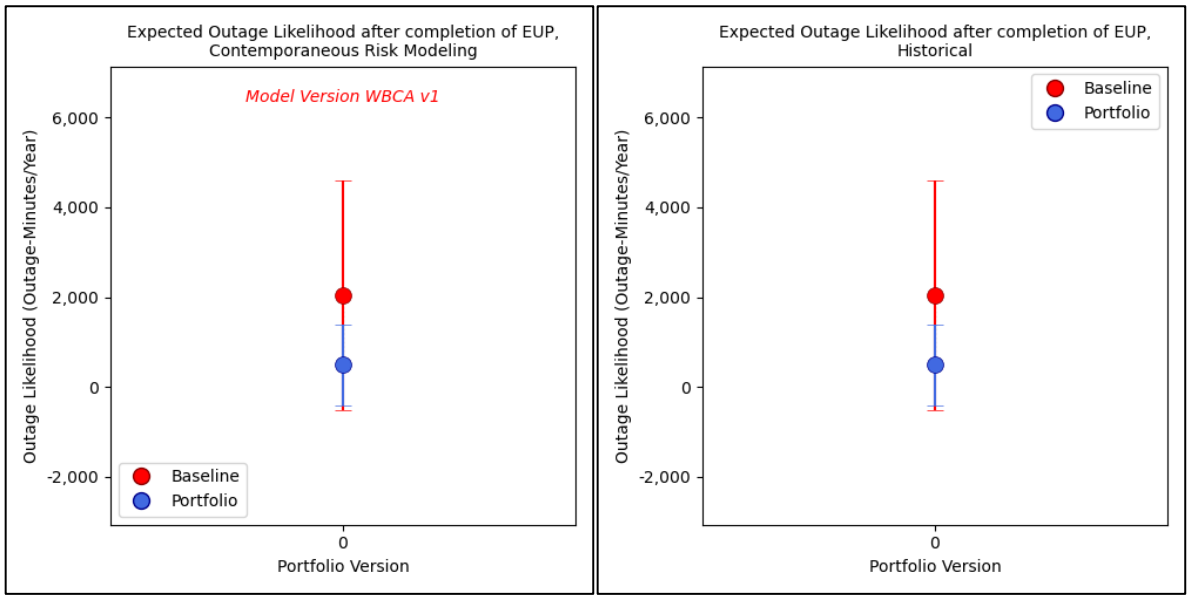
- Left: A plot showing the mean and standard deviation of the Outage Program Risk's Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using the most recent version of the model, WBCA v1. The x-axis denotes a different version of the Portfolio.
- Right: A plot showing the mean and standard deviation of the Outage Program Risk's Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio using WBCA v1, which was most recent at the time the Portfolio was updated.

5. Outage Program Consequence and Likelihood

KDMM graphs are not produced for Outage Program Consequence, as EUP mitigations only minimally modify the consequence after a PSPS or EPSS related outage has occurred, thus the modeled value after EUP mitigation is unchanged.

Figure PCS-13E reflects the anticipated reduction in the system's Outage Program Likelihood that will be achieved by implementing Portfolio 0.

FIGURE PCS-13E:
KDMM DEVELOPMENT: CHANGES IN PORTFOLIO OUTAGE PROGRAM LIKELIHOOD



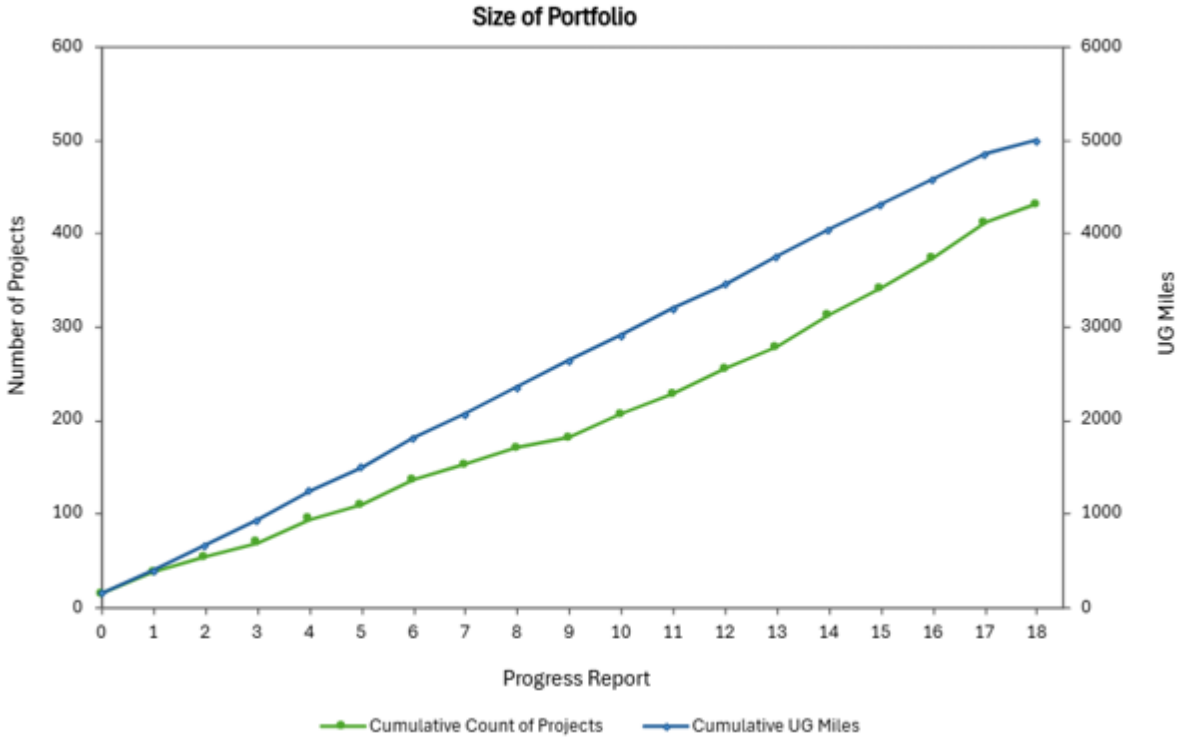
- Left: A plot showing the mean and standard deviation of the Outage Program Likelihood's Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using the most recent version of the model, WBCA v1. The x-axis denotes a different version of the Portfolio.
- Right: A plot showing the mean and standard deviation of the Outage Program Likelihood's Baseline (red) and modeled value after EUP mitigation (blue) of Circuit Segments in the Portfolio, using WBCA v1, which was the most recent version at the time the Portfolio was updated.

6. Portfolio Development Graph

Figure PCS-14, below, shows the size of the Portfolio based on the number of Undergrounding Projects and total underground circuit miles. It includes the first 28 Projects in Portfolio 0.

The projected growth shown in the graph assumes scoping approximately 45 underground miles per month, which drives the rate at which the Portfolio will expand over time.

FIGURE PCS-14:
PORTFOLIO DEVELOPMENT OVER PROGRESS REPORTS



H. Portfolio Coversheet Organization (EUP Guidelines Section 2.8.6.4)

The Portfolio Coversheet must be organized as follows:

Table 7. Portfolio Coversheet Organization

Section	*Requirements*
Narrative Justification	*See Section 2.8.6.1 of these Guidelines*
Key Decision-Making Metrics Profiles	*See Section 2.8.6.2 of these Guidelines*
Project Variable Modifiers	*See Section 2.7.7 of these Guidelines*
Portfolio Development	*See Section 2.8.6.3 of these Guidelines*

PG&E's Portfolio Coversheet complies with this required organization with one exception. PG&E is submitting the Project Variable Modifiers with the Progress Report consistent with other requirements in the EUP Guidelines.[205] The response to EUP Guidelines Section 2.7.7 is in Chapter 7, Section K pursuant to EUP Guidelines, Appendix B, p. B-4.

I. Chapter Summary

This chapter establishes PG&E's reporting framework for the Portfolio Coversheet, describing how we will meet the requirements of SB 884 and EUP Guidelines Section 2.8 through standardized metrics, data submissions, validation processes, and Portfolio level reporting. Together, these elements ensure consistent, transparent, and comparable reporting over time and support regulatory review of Portfolio composition and risk outcomes.

J. Chapter 9 Supporting Attachments Index

The attachments/workpapers in Table 9-4 below support this chapter.

[205] The Project Variables Modifiers (PVM) Table is in the Progress Report rather than the Portfolio Coversheet as stated in EUP Guidelines Section 2.8.5.2. See EUP Guidelines Appendix C Sections C.2 and Section C.2.1. As such, PG&E includes PVM in the JSON Submission in Attach. A-3 to the Progress Report. PVM data is not included in the Portfolio Coversheet.

TABLE 9-4:
CHAPTER 9 SUPPORTING ATTACHMENTS/WORKPAPERS INDEX

Line No.	EUP Section	EUP Location	Workpaper / Table Name	File Name
1	9.C.5	Attachment A-2	Table C.5 Risk Model Backtesting Table	PGE_Initial_2026-09-30_T5_R0
2	9.C.5.b	Attachment B	WP001 (Mitigation Effectiveness Analysis)	PGE_WP001_2026-09-30_Mitigation Effectiveness Analysis_R0
3	9.C.5.b	Attachment B	WP015 (Distribution Event Probability Models Version 4 (DEPM v4))	PGE_WP015_2026-09-30_DEPM v4_R0
4	9.C.5.b	Attachment B	WP018 (EUP EPSS Risk Model v1 Documentation)	PGE_WP018_2026-~~09-30~~11-02_EUP EPSS Risk Model v1 Documentation_R0
5	9.C.5.b	Attachment B	WP020 (EUP PSPS v1 Risk Model Documentation)	PGE_WP020_2026-09-30_EUP PSPS Risk Model v1 Documentation_R0
6	9.E	Attachment A-1	Progress Report 0 Portfolio Coversheet	PGE_AtchA_2026-~~09~~10-30_Progress Report 0 Portfolio Coversheet_R0
7	9.E.4	Attachment B	WP021 (KDMM Formulas)	PGE_WP021_2026-09-30_KDMM Formulas_R0