

PG&E: Choosing the Next Wildfire-Risk Mitigation Tranche

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Decision scope: Hypothetical next-tranche prioritization among targeted undergrounding, overhead hardening, and operational mitigation

Case convention: This is a teaching exercise. The strategic assignment is hypothetical; PG&E has not publicly disclosed this specific decision or a discretionary tranche. Statements from the company and CPUC staff are attributed. No later events or outcomes are included.

The assignment

Assume you advise a hypothetical PG&E strategy team planning its next tranche of distribution wildfire-risk mitigation. Recommend how the team should prioritize work among (1) undergrounding selected high-risk circuit segments, (2) overhead hardening such as covered conductor and stronger poles, and (3) operational measures such as EPSS, PSPS, detection and monitoring. Explain what evidence should guide the choice, what trade-offs matter, and what additional data you would request before committing to a project mix.

Use only information public by November 8, 2024. The alternatives are a teaching frame, not a description of an announced management choice. Do not assume that existing approved work is freely reallocable. PG&E's November 7 filing said its 10-year SB 884 undergrounding plan had not yet been submitted [S1]; the California Public Utilities Commission's Safety Policy Division (SPD) published a staff evaluation of the company's 2024 RAMP filing on November 8. That report is staff analysis, not a Commission decision approving a technology mix or project budget. [S4]

A portfolio of distinct interventions

PG&E's regulated utility describes wildfire mitigation as a collection of measures: undergrounding, system hardening, EPSS, PSPS, vegetation management, inspections, downed-conductor detection, partial-voltage force-outs, transmission controls, weather stations, and risk modeling. These measures address different failure pathways and create different service impacts. A mile constructed is an activity measure; it does not by itself establish how many ignitions, acres burned, outages, or customer interruptions were avoided. [S1]

In the third quarter of 2024, PG&E reported constructing 58 miles of underground line and 66 miles of covered line with stronger poles. For the first nine months of 2024, it reported 120 miles underground and 113 miles of covered line with stronger poles. Those are period-specific reported totals. The company's earnings presentation separately reported 737 miles completed under its 10,000-mile Undergrounding Program since it began in 2021 and 1,877 system-hardening miles through September 30, 2024; the hardening total includes data beginning in 2018. For 2024, PG&E showed targets of 250 miles underground and 280 line miles

hardened. Targets are not actual results, and cumulative figures cover different periods and program scopes. [S2-S3]

Exhibit 1. Progress and targets reported by PG&E

Measure	Reported amount	Period / scope	Interpretation
Underground line constructed	58 miles	Q3 2024	Company-reported construction activity
Underground line constructed	120 miles	First nine months 2024	Company-reported year-to-date activity
Undergrounding program completed	737 miles	Program-to-date through Sept. 30, 2024	10,000-mile program began in 2021
Covered line with stronger poles	66 miles	Q3 2024	Company-reported construction activity
Covered line with stronger poles	113 miles	First nine months 2024	Company-reported year-to-date activity
System hardening	1,877 miles	Cumulative through Sept. 30, 2024	Company presentation says this measure includes data beginning in 2018
Undergrounding target	250 miles	Full year 2024 target	Forecast/target, not actual
Line hardening target	280 miles	Full year 2024 target	Forecast/target, not actual

Sources: PG&E's Q3 2024 release and earnings presentation. Measures have different periods and scopes; "system hardening" includes more than the current-year covered-line figure. [S2-S3]

PG&E also stated that its efforts had "significantly reduced" CPUC-reportable ignitions and acres burned from utility-related ignitions. In the same filing, it identified weather, vegetation, infrastructure, fire location, suppression, workforce availability, costs and regulatory recovery as relevant factors. The company's statement is not a controlled estimate of the causal effect of any single intervention. [S1]

What did the staff scenarios say?

The SPD evaluation compares modeled mitigation scenarios for the five highest-risk tranches. Table 1-7 reports net present value (NPV) risk reduction, NPV cost and a cost-benefit ratio (CBR). For its undergrounding scenario, staff reports \$45.59 billion in modeled NPV risk reduction at \$4.625 billion NPV cost. The covered-conductor scenario reports 65% of that modeled risk reduction at 37% of the cost, with CBR 17.44. The PSPS-plus-EPSS scenario reports \$19.24 billion in modeled risk reduction at \$49 million NPV cost, with CBR 392.33. These are staff-model outputs under specified assumptions, not realized results or returns earned by PG&E. [S4]

The scenarios do not represent equivalent customer experiences. The report discusses interruption impacts and identifies PSPS as a last resort. Covered conductor and undergrounding are physical treatments with different construction, maintenance, and outage characteristics; operational de-energization can avoid some energized-line risks while interrupting service. The ratios therefore do not answer the decision on their own. SPD also

reports that PG&E did not provide requested circuit-segment-level cost, risk-reduction and CBR data for all proposed undergrounding circuits, limiting validation of project-level choices. [S4]

Exhibit 2. Selected CPUC staff scenario outputs for the top five risk tranches

Staff scenario	Modeled NPV risk reduction	Modeled NPV cost	Reported CBR	Boundary to keep in view
Undergrounding	\$45.59bn	\$4.625bn	As reported in Table 1-7	Staff scenario; not an actual project portfolio or realized return
Covered conductor	65% of undergrounding scenario	37% of undergrounding scenario cost	17.44	Staff scenario; different delivery and reliability characteristics
PSPS + EPSS	\$19.24bn	\$49m	392.33	Staff scenario; power shutoffs can impose customer interruption costs

Source: CPUC SPD, *Evaluation Report on PG&E 2024 RAMP*, printed p. 62, Table 1-7. Figures are NPV scenario estimates attributed to staff. SPD's report is an evaluation, not a Commission approval. [S4]

Capital and regulatory context

PG&E Corporation increased its 2024-2028 capital plan by \$1 billion to \$63 billion. The company said the increase responded to customer demand, had already been approved by the CPUC, and had already been financed through junior subordinated notes. That increase is not a newly available wildfire-only budget. Separately, management said operating and maintenance savings were reinvested in risk-mitigation programs such as inspections and corrosion maintenance. [S2]

Under SB 884, a utility submits a 10-year undergrounding plan for review before seeking conditional cost approval. At the cutoff, PG&E said revised draft guidelines had been issued and final guidelines were expected later in 2024; PG&E expected to submit its plan afterward. The company had not filed the plan described in its 10-Q. SPD's RAMP report was a staff evaluation feeding future regulatory proceedings, not final approval of its scenario outputs or PG&E's proposed costs. [S1, S4]

Evidence beyond PG&E

Larsen's 2016 peer-reviewed study develops a societal cost-benefit framework and applies it to Texas investor-owned utility transmission and distribution lines through 2050. It models life-cycle costs, outage costs, aesthetic/property-value proxies, health and safety, and ecosystem restoration. Its base case estimates a roughly \$21 billion net social loss for blanket undergrounding, while a restricted urban-only analysis is near breakeven on average. The outcome is sensitive to line life, construction cost, outage valuation, customer density, discounting and reliability assumptions. The paper is useful for organizing a project-level comparison; its Texas model is not a California wildfire estimate and its dollars should not be transferred to PG&E. [A1]

Wang and coauthors' 2023 *Nature Energy* article examines California distribution-grid vulnerability and cost allocation. The publisher abstract reports that lower-income communities have lower shares of underground lines and more wildfire-vulnerable overhead lines and poles. The authors propose an income-threshold allocation under which some costs are spread across utility-wide ratepayers. Only the abstract was available to this case team; use it as a prompt about who pays and benefits, not as a quantified PG&E estimate. [A2]

Questions for the team

1. What criteria should determine whether a circuit segment is undergrounded, hardened overhead, or managed through operational measures?
2. How should the team weigh the staff scenario ratios against reliability, customer interruption, construction feasibility, life-cycle cost, and equity?
3. Which additional circuit-level data and independent validation would you require before recommending a mix?
4. How should the team account for uncertainty in weather, vegetation, ignition probability, fire spread, asset condition, and cost recovery?
5. What metrics would distinguish completed work from demonstrated risk reduction and customer benefit?

Sources and cutoff

All case information is limited to November 8, 2024, 11:59 p.m. ET. PG&E Corporation is the holding company; Pacific Gas and Electric Company is the regulated utility. The case excludes later plans, regulatory decisions, implementation results, and fire outcomes.

- **[S1]** Pacific Gas and Electric Company and PG&E Corporation, joint Form 10-Q, quarter ended September 30, 2024, filed November 7, 2024. [SEC filing index](#); [Utility filing HTML](#). Wildfire risk: Part II, Item 1A, printed pp. 13-14; SB 884 plan: Item 2, "SB 884 10-Year Distribution Undergrounding Program."
- **[S2]** PG&E Corporation, "PG&E Corporation Reports Strong Third-Quarter Results; Strengthens 2024 Guidance; Initiates 2025 Guidance; Grows 5-Year Capital Plan," November 7, 2024. [Company release](#).
- **[S3]** PG&E Corporation, Q3 2024 earnings presentation, furnished November 7, 2024. [SEC exhibit](#), slides 30-31.
- **[S4]** California Public Utilities Commission, Safety Policy Division, *Evaluation Report on PG&E 2024 RAMP*, dated November 8, 2024. [Official report](#); Table 1-7, printed p. 62; "CBR Calculations," printed p. 68; additional scenario discussion, printed pp. 78-80. Staff evaluation, not a Commission decision.
- **[A1]** Peter H. Larsen, "A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines," *Energy Economics* 60 (2016), 47-61. [Full article](#). DOI: [10.1016/j.eneco.2016.09.011](#).
- **[A2]** Zhecheng Wang, Michael Wara, Arun Majumdar, et al., "Local and Utility-Wide Cost Allocations for a More Equitable Wildfire-Resilient Distribution Grid," *Nature Energy* 8 (2023), 1097-1108. [Publisher page](#). This case team reviewed the publisher abstract only.