

Wildfire-Resilient Grids

Utility Liability, Undergrounding,
and Mitigation Strategy



WHITEPAPER

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SCAN TO EXPLORE



Abstract

Utility-sparked wildfires have become one of the largest financial risks in the North American power sector, producing tens of billions of dollars in **wildfire liability**, a string of credit downgrades, and the 2019 bankruptcy of the nation's largest investor-owned utility. This paper evaluates the full toolkit of **utility wildfire mitigation**: selective **undergrounding power lines**, covered conductors and other forms of **grid hardening**, fast-trip protection settings, the **public safety power shutoff**, and AI-enabled ignition detection. It weighs the cost, effectiveness, and ratepayer impact of each strategy, examines the changing liability and insurance landscape, including California's Wildfire Fund and the wave of state liability laws enacted since 2020, and proposes a risk-based framework for prioritizing mitigation investment.

About this Paper

Prepared by Vedeni Energy, this white paper synthesizes regulatory filings, utility wildfire mitigation plans, court records, rating-agency commentary, and independent academic analysis available through September 2026. It takes a technology-neutral, cost-per-unit-of-risk stance: no single measure is presumed superior, and each is judged by the ignition risk it removes per dollar spent and per hour of customer outage imposed.

Audience and Use Cases

Utility executives, wildfire mitigation and asset-management teams, regulators and consumer advocates, legislators drafting liability reform, investors and credit analysts, and insurers underwriting utility risk. Engineering and workforce leaders planning multi-year hardening programs will also find the cost and deployment benchmarks useful.

Executive Summary

Wildfire has moved from a California anomaly to a balance-sheet risk for utilities across the West, the Plains, and beyond, and the industry's response now ranks among the largest capital programs in its history.

Since 2017, fires linked to utility equipment have destroyed tens of thousands of structures and driven liabilities that dwarf most utilities' annual earnings. PG&E entered Chapter 11 in January 2019 facing more than \$30 billion in fire-related claims. Hawaiian Electric's roughly \$2 billion share of the Maui settlement pushed it to junk-grade ratings. PacifiCorp has accrued nearly \$3 billion for the 2020 Oregon fires and slid to the edge of investment grade. Southern California Edison now faces an Eaton Fire exposure that analysts place in the low-to-mid teens of billions of dollars, on top of more than \$10.5 billion already paid for earlier fires.

Utilities have answered with multi-year wildfire mitigation plans. California's three largest investor-owned utilities were authorized roughly \$16 billion of mitigation between 2019 and 2023, and wildfire costs now account for up to about a fifth of some customers' bills. Outside California, Xcel Energy's \$1.9 billion Colorado plan, PacifiCorp's roughly \$2 billion 2025-2027 program, and Texas's new statewide plan mandate show the model spreading quickly.

The evidence suggests that no single tool wins everywhere. Fast-trip protection settings deliver the largest near-term risk reduction per dollar but impose reliability costs. Covered conductor protects roughly four miles for the cost of one undergrounded mile. Undergrounding nearly eliminates ignition risk on the segment it replaces but is slow and capital-intensive, making it best reserved for the highest-consequence corridors. The winning strategy is a portfolio sequenced by risk: operate protectively now, harden broadly, underground selectively, and invest in detection and data that make every other dollar work harder.

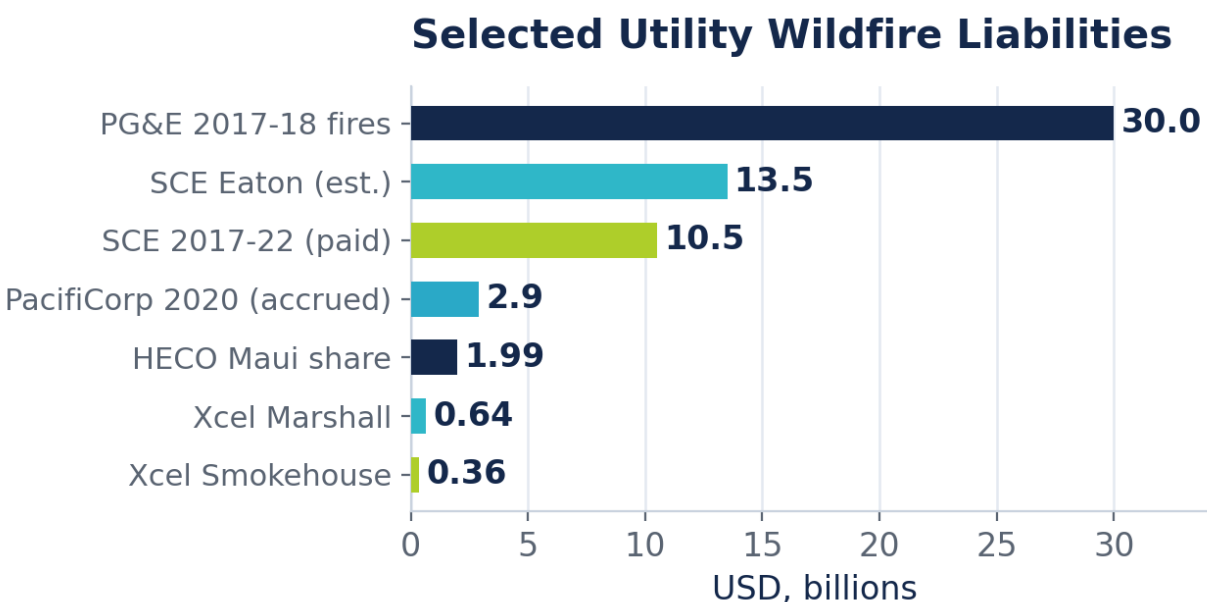


Figure 1. Selected utility wildfire liabilities, estimated, accrued, or paid (USD billions).

The New Economics of Utility Wildfire Risk

A utility's wildfire exposure is now defined less by how often its equipment ignites a fire than by the rare catastrophic event that can erase a decade of earnings in a single afternoon.

The modern era of utility wildfire liability began with the 2017 Northern California fires and the November 2018 Camp Fire, which killed 85 people and destroyed nearly 19,000 structures in and around Paradise. PG&E filed for Chapter 11 protection in January 2019, citing more than \$30 billion in potential fire-related costs. It emerged in July 2020 after funding a Fire Victim Trust with \$5.4 billion in cash plus more than a fifth of the company's stock, paying \$11 billion to insurance subrogation claimants, and contributing roughly \$5 billion to the new state Wildfire Fund.

The pattern has since repeated in very different geographies. The August 2023 Lahaina fire on Maui killed more than 100 people and destroyed more than 2,200 structures. Hawaiian Electric joined a global settlement exceeding \$4 billion, of which its share is about \$1.99 billion, and all three major rating agencies cut the company to speculative grade within weeks. In Oregon, juries in the James class action found PacifiCorp liable for several of the 2020 Labor Day fires; by early 2026 damages trials had produced \$1.23 billion in verdicts, settlements had reached about \$2.2 billion across roughly 4,500 claims, and S&P; had lowered PacifiCorp to BBB-.

Xcel Energy settled Colorado's 2021 Marshall Fire litigation for about \$640 million in 2025 without admitting fault, and has accepted responsibility for the February 2024 Smokehouse Creek Fire, the largest in Texas history at more than one million acres, settling about \$361 million of claims. S&P; downgraded Xcel from A- to BBB+ weeks after that fire, citing greater than anticipated wildfire risk. Most recently, the January 2025 Eaton Fire in Los Angeles County destroyed more than 9,400 buildings; Edison International has acknowledged that its equipment was likely associated with the ignition, and the event triggered a 26 percent single-episode decline in its share price.

\$30B+

PG&E fire claims at 2019 bankruptcy filing

~\$2.9B

PacifiCorp accrued losses, 2020 Labor Day fires

9,400+

buildings destroyed in the 2025 Eaton Fire

The risk is also spreading geographically. Federal ignition data show power-line-caused fires rising from roughly 200 per year in the early 1990s to around 2,500 per year today, and these fires burn larger on average than those from any other human cause. Texas recorded about 4,474 power-line ignitions in the most recent decade compared with 67 three decades earlier, and North Carolina rose from 32 to more than 2,900. Station records show that the annual number of fire-weather days

has grown by more than a month in the Southwest since the early 1970s. A utility does not need to operate in California to carry California-scale exposure.

KEY TAKEAWAY



Wildfire liability is now a system-wide credit risk, not a California footnote; the question for every utility with dry, windy terrain is how quickly it can buy down the tail.



Liability, Insurance, and State Wildfire Funds

The legal regime a utility operates under shapes its wildfire exposure as much as the condition of its poles and wires.

California applies the doctrine of inverse condemnation, which makes a utility strictly liable for property damage caused by its equipment regardless of negligence. Investor-owned utilities may then seek to recover those costs from customers only if regulators find that they acted prudently. After 2019, that combination left investors facing unlimited, uninsurable exposure. The legislature responded with AB 1054, which created a \$21 billion Wildfire Fund financed equally by shareholder contributions and a ratepayer charge, established an annual safety certification, shifted the prudence burden in favor of certified utilities, and capped a utility's reimbursement to the fund at 20 percent of its transmission and distribution equity rate base over three years.

The Eaton Fire exposed the limits of that design. Officials warned that claims could exhaust the original fund, and in September 2025 the state enacted SB 254, which adds a continuation account of up to \$18 billion funded roughly half by ratepayer-backed bonds and half by shareholders, extends the customer charge to 2045, and requires \$6 billion of mitigation capital to be securitized rather than added to equity rate base. A broader 2026 reform package that would have capped some non-economic damages and limited insurer subrogation died on the final day of the legislative session, and rating agencies promptly signaled that further fund depletion could trigger downgrades of both PG&E and SCE.

State / Year	Mechanism	Key feature
California 2019 / 2025	AB 1054; SB 254	\$21B fund plus up to \$18B continuation account
Utah 2020 / 2024	HB 66; SB 224	Plan compliance shields negligence; self-insurance fund
Wyoming, Idaho, N. Dakota 2025	Plan-based statutes	Presumption of reasonableness if plan followed
Montana, Arizona 2025	HB 490; HB 2201	Approved plans limit liability exposure
Kansas 2025	HB 2107	Caps punitive damages at \$5M
Texas 2025	HB 145	Mandatory utility plans by January 2027
South Dakota 2026	SB 36	Plan framework and liability limits

Table 1. Selected state wildfire liability and mitigation-plan legislation.

Beyond California, legislatures have moved toward a different model: rather than socializing losses through a fund, they condition liability protection on compliance with a regulator-approved wildfire mitigation plan. Utah led in 2020, and 2025 alone produced statutes in Wyoming, Idaho, Kansas, North Dakota, Washington, Arizona, Montana, and Texas. Roughly thirteen to fifteen states now have some combination of plan requirements and liability limits. Oregon, home of the James litigation, considered but did not pass comparable bills in 2025, and no federal liability framework has been enacted, although Congress has advanced forest-management and right-of-way-clearing legislation.

Insurance markets have hardened in parallel. Commercial carriers have withdrawn capacity, added wildfire sub-limits, and raised premiums sharply; Xcel reported a nearly 400 percent year-over-year increase in Colorado, and Utah created its fund after premiums became prohibitive. PG&E moved fully to self-insurance for wildfire in late 2023. Utility-owned mutuals and captives, and the catastrophe-bond market that PG&E first tapped in 2018, provide partial relief, but the practical result is that most large wildfire losses now fall on shareholders, customers, or state funds rather than on traditional insurers.

Where liability is strict and insurance is scarce, mitigation spending is not merely a safety program. It is the utility's principal form of risk financing.

KEY TAKEAWAY



Plan-based liability statutes reward utilities that can prove disciplined, risk-ranked mitigation, which makes the quality of the wildfire mitigation plan itself a financial asset.



Undergrounding Power Lines

Undergrounding is the only measure that nearly eliminates ignition risk on the segment it replaces, and it is also the slowest and most expensive.

PG&E's July 2021 pledge to bury 10,000 miles of distribution line, about 40 percent of its overhead mileage in high fire-threat districts, reframed the national debate. Progress since then has been real but measured. The utility energized its 1,000th underground mile in October 2025, passed roughly 1,370 miles by September 2026, and plans to exceed 1,900 cumulative miles by the end of 2027. Its 2026-2028 wildfire mitigation plan, approved by California's Office of Energy Infrastructure Safety in February 2026, adds about 1,100 underground miles. A longer-range ten-year undergrounding plan under SB 884 was still being prepared in 2026, with work under that framework not expected before 2028.

PG&E Cumulative Underground Miles

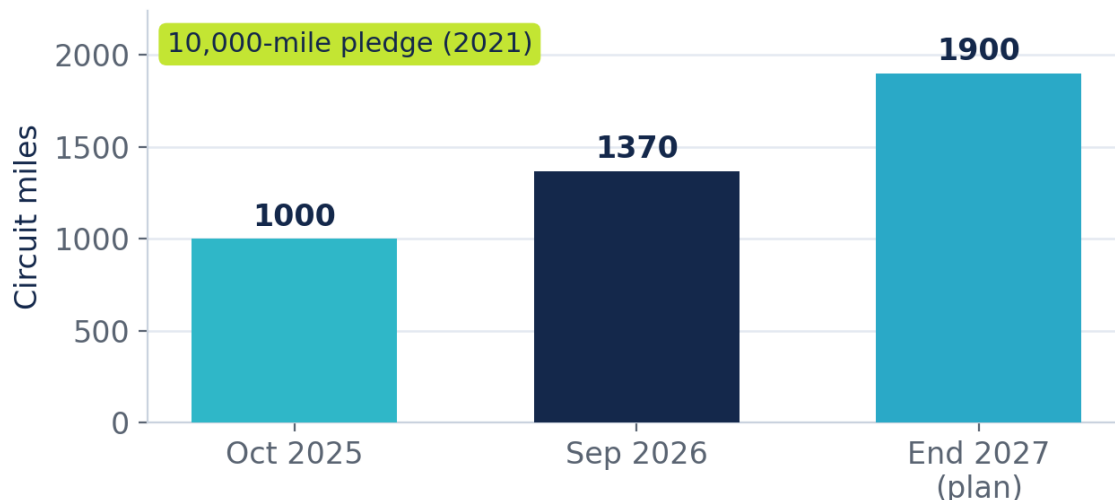


Figure 2. PG&E cumulative underground miles energized, with 2027 plan.

Unit costs have fallen but remain high. PG&E reports that its cost per mile declined from about \$4 million to about \$3.1 million through trenching innovation and scale, and targets roughly \$2.5 million. Joint utility data for 2022 put undergrounding at about \$2.0 million per circuit mile for SDG&E, \$2.3 million for SCE, and \$2.5 million for PG&E, while SCE's rebuild of the 2025 burn scars is running near \$4 million per mile. Recent regulatory staff ranges span roughly \$2 million to more than \$6 million depending on terrain, rock, and permitting.

Regulators have pushed back on scope. In PG&E's 2023 rate case the California Public Utilities Commission approved about 1,230 underground miles rather than the roughly 2,100 requested, pairing them with 778 miles of covered conductor. The state's Public Advocates Office argues that for the cost of undergrounding one mile, a utility can protect almost four miles with covered conductor, and that covered conductor can be installed in one to two years compared with three to four. Independent academic work estimates that broad undergrounding could cost more than \$100 million per avoided ignition, roughly seven times the cost of achieving the same benefit with fast-trip settings.

Those critiques do not make undergrounding the wrong answer; they make it a targeted one. It is most defensible where consequence is extreme and other tools fall short: egress-constrained communities, corridors that would otherwise need frequent shutoffs, and wind-exposed terrain where covered conductor cannot stop tree strikes. Undergrounding also delivers co-benefits that benefit-cost analyses often omit, including fewer power shutoffs, lower long-run vegetation costs, and storm resilience.

10,000

mile PG&E undergrounding pledge
(2021)

~\$3.1M

PG&E cost per underground mile
(2025)

~4x

miles of covered conductor per
undergrounded mile

KEY TAKEAWAY



Underground where consequence and shutoff burden are highest; everywhere else, faster and cheaper tools buy more risk reduction per ratepayer dollar.

Covered Conductor and Overhead Grid Hardening

Covered conductor has become the workhorse of grid hardening because it can be deployed at scale, quickly, and at a fraction of the cost of trenching.

Covered conductor wraps the energized wire in insulating layers so that contact with a branch, a bird, a balloon, or a neighboring phase is far less likely to produce the arcing and sparks that start fires. Southern California Edison has made it the backbone of its plan, installing about 6,500 circuit miles since 2018 at roughly \$900,000 per mile and covering about 90 percent of its overhead distribution in high fire-risk areas by the end of 2025. SCE credits its combined program with an 85 to 88 percent reduction in catastrophic wildfire risk compared with pre-2018 conditions.

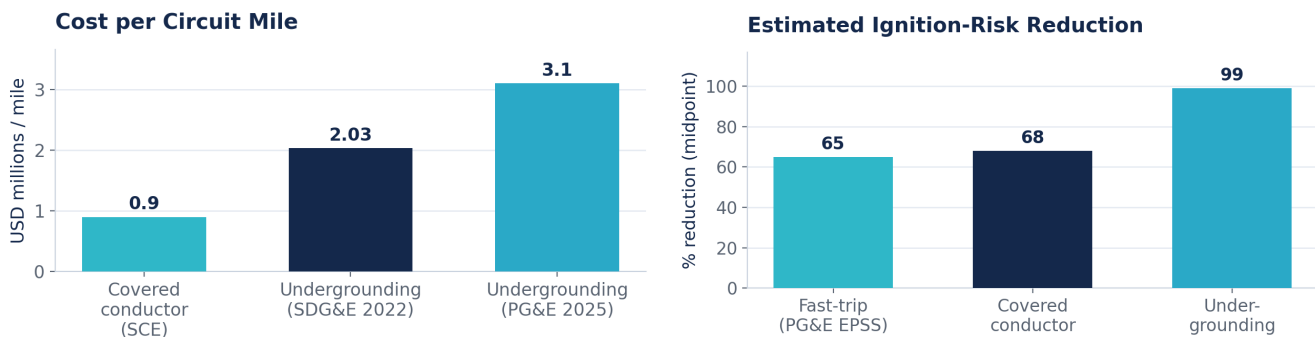


Figure 3. Unit cost (left) and estimated ignition-risk reduction (right) by mitigation type.

Effectiveness estimates vary by utility and method. The joint utility Covered Conductor Working Group reports estimates of about 72 percent for SCE, 64 percent for PG&E based on outage data, roughly 66 percent for SDG&E, and about 70 percent for PacifiCorp's spacer-cable designs. SCE observed recorded faults falling about 70 percent on fully covered circuits between 2019 and 2022. PG&E estimates that its overhead hardening package of covered wire and stronger poles reduces ignition risk by about two-thirds. The residual risk is mainly from whole trees or limbs falling through the line, equipment failure at connectors and transformers, and pole failure in extreme wind.

That residual risk is why effective overhead hardening is a package rather than a wire. Programs combine covered conductor with composite or steel poles, non-expulsion fuses, upgraded transformers and connectors, wider spacing, targeted hazard-tree removal, and more frequent inspection. The Smokehouse Creek Fire, which began when a decayed pole already flagged for priority replacement failed, illustrates that basic asset condition can matter as much as advanced technology. Xcel's Colorado plan, for example, commits to more than 10,000 pole replacements alongside its other hardening measures.

Workforce is now a binding constraint. Hardening thousands of miles per year requires lineworkers, civil crews, inspectors, and protection engineers in numbers that many utilities and contractors do not yet have, and labor availability increasingly sets the real pace of mitigation.

KEY TAKEAWAY



Covered conductor, paired with pole, equipment, and inspection upgrades, captures most of undergrounding's ignition benefit at roughly a quarter of the cost and several times the speed.



Fast-Trip Settings and Public Safety Power Shutoffs

Operational measures are the fastest way to cut ignition risk, but they transfer part of the cost from ratepayers' bills to their reliability.

Fast-trip, or sensitive relay, settings make protective devices de-energize a line within roughly a tenth of a second when they sense a fault, limiting the energy available to ignite vegetation. PG&E's Enhanced Powerline Safety Settings, known as EPSS, were rolled out across about 25,500 distribution miles in high fire-threat districts beginning in 2021. PG&E reported 72 percent fewer reportable ignitions on EPSS-enabled lines in 2023, 65 percent fewer in 2024 against a 2018-2020 baseline, and about 58 percent fewer in 2025 against a later baseline. In 2025 it recorded 57 reportable ignitions in high fire-threat districts, the lowest since tracking began, with only one reaching ten acres.

EPSS Ignition Reduction (2023)

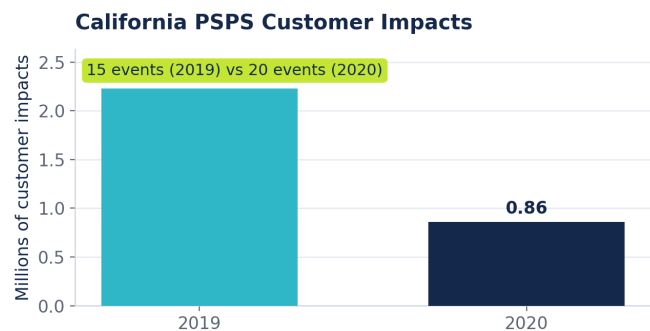
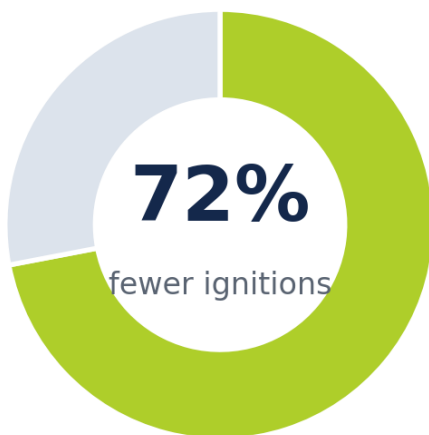


Figure 4. PG&E EPSS ignition reduction (left) and California PSPS customer impacts (right).

The price is unplanned outages. Because fast-trip events look like ordinary faults, customers experience them as more frequent and less predictable interruptions, and California regulators now require monthly outage reporting for these programs. Xcel, PacifiCorp, and other western utilities have adopted similar settings, generally enabling them seasonally or when fire-weather thresholds are met. Falling-conductor protection, pioneered by SDG&E, extends the idea to transmission by tripping a broken wire before it reaches the ground.

The public safety power shutoff is the blunt instrument of last resort. In 2019 California utilities logged more than 2.2 million customer impacts across 15 events, including a late-October PG&E event that de-energized about 968,000 customers for an average of 55 hours; one estimate puts the economic cost of the October 2019 events alone at up to \$2.5 billion. Utilities have since shrunk events through sectionalizing, better weather modeling, and hardening, so that PG&E ran seven narrowly scoped events in 2024 and four in 2025. Shutoffs are now spreading: Xcel's first proactive shutoff in Colorado in April 2024 affected about 55,000 customers, and a larger December 2025 Front Range event drew intense regulatory and community scrutiny.

Every hour of shutoff is a mitigation cost, paid by customers in lost business, spoiled medicine, and disrupted lives, and it belongs in the same ledger as capital spending.

~0.1 s

EPSS de-energization time after a fault

57

PG&E reportable HFTD ignitions in 2025

968K

customers in PG&E's late Oct. 2019 shutoff

KEY TAKEAWAY



Fast-trip settings and PSPS buy time while hardening proceeds; the goal of capital investment should be to make them rarer, smaller, and shorter.

AI-Enabled Detection and Situational Awareness

Detection technology is shortening the time between ignition and response, and turning fire weather into data that operators can act on circuit by circuit.

California's ALERTCalifornia network now includes more than 1,200 cameras whose feeds are screened by artificial intelligence. In 2025 it flagged about 3,600 incidents, and more than half of its alerts came before the first 911 call. Commercial providers such as Pano AI serve more than a dozen U.S. utilities, covering tens of millions of acres. PG&E alone operates more than 600 AI-enabled cameras and more than 2,000 weather stations, while PacifiCorp has expanded from 55 weather stations in 2020 to about 600.

Detection is moving onto the grid itself and into orbit. Line-mounted sensors, such as the thousands of Gridware units PG&E has installed, listen for the vibration and electrical signatures of contact, broken hardware, or vegetation strikes. Texas A&M's Distribution Fault Anticipation technology, deployed on about 1,000 circuits worldwide, analyzes waveform data to flag failing equipment weeks before it fails. The first three operational FireSat satellites, launched by mid-2026, are designed to detect fires as small as about five meters across, with a goal of hourly global revisit by 2029.

1,200+

AI-screened cameras in
ALERTCalifornia

>50%

of 2025 alerts arrived before a 911
call

~500M

fire-spread simulations run daily for
utilities

The most consequential use of AI may be in planning rather than detection. Fire-spread models such as Technosylva's run hundreds of millions of simulations daily to estimate the consequence of an ignition at any point on the network under forecast weather. Combined with asset-condition and outage data, those consequence scores drive where utilities harden, when they enable fast-trip settings, and how narrowly they can scope a shutoff. PG&E's modeling suggests its 2024 shutoffs may have averted up to about 76,000 acres of fire.

Detection reduces the consequence of an ignition; it does not prevent one. Its value is highest when paired with fast response, sectionalized circuits, and models good enough to trust with operational decisions.

KEY TAKEAWAY



Sensors, cameras, satellites, and fire-spread models are the connective tissue of a modern mitigation program, making every hardening and operating decision more precise.



A Risk-Based Framework for Prioritizing Mitigation

With wildfire costs already a double-digit share of some bills, the central question is no longer whether to invest, but how to spend each dollar where it removes the most risk.

Affordability now constrains strategy as much as safety does. California's three largest investor-owned utilities were authorized about \$16 billion of mitigation between 2019 and 2023, plus about \$11 billion of insurance and catastrophic-event costs. Wildfire costs made up about 18 percent of PG&E's system costs in 2023, 12 percent of SCE's, and 9 percent of SDG&E's, and residential rates rose roughly 48 to 67 percent over 2019-2023 against about 18 percent general inflation. Regulators are responding by demanding clearer evidence of risk reduced per dollar.

Wildfire Share of California IOU System Costs, 2023

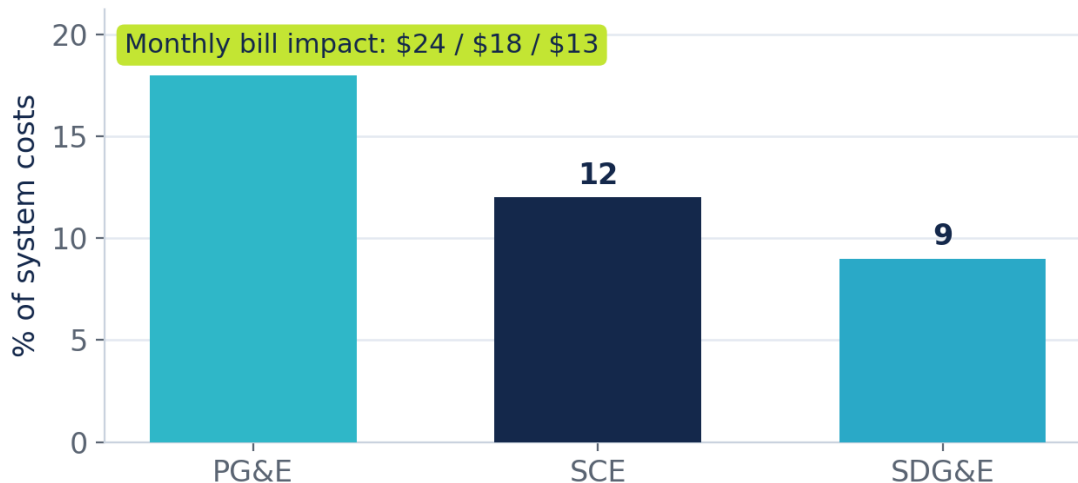


Figure 5. Wildfire-related share of California IOU system costs, 2023.

We recommend a five-step, risk-based framework. First, quantify risk at the circuit-segment level as the product of ignition likelihood and wildfire consequence, using asset condition, vegetation, outage history, terrain, fuels, and community egress. Second, compute a risk-spend efficiency for each feasible measure on each segment, counting capital and operating costs, customer outage costs from fast-trip and PSPS, and co-benefits such as reduced vegetation work and storm resilience. Third, sequence the portfolio: deploy operational measures immediately, harden broadly with covered conductor and equipment upgrades, and reserve undergrounding for the highest-consequence segments where it also eliminates recurring shutoffs. Fourth, instrument the network so that results are measured, not assumed. Fifth, publish results and update annually, creating the audit trail that plan-based liability statutes and rating agencies increasingly reward.

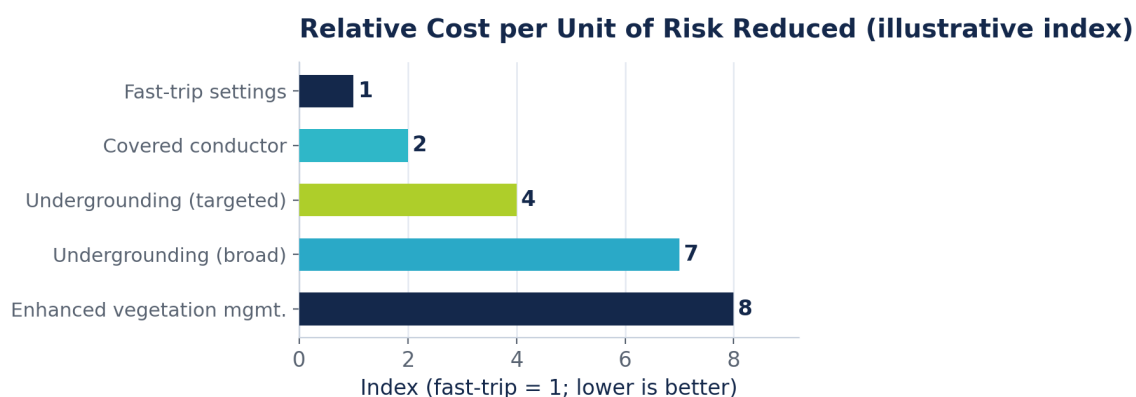


Figure 6. Illustrative relative cost per unit of risk reduced, synthesized from published academic and regulatory comparisons.

Measure	Cost / mile	Risk reduction	Speed	Best use
Fast-trip settings	Low	~58-72%	Months	All HFTD circuits, now
Covered conductor	~\$0.9M	~64-72%	1-2 yrs	Broad overhead hardening
Undergrounding	~\$2-4M+	~99%	3-4 yrs	Highest-consequence corridors
PSPS	Low capital	Very high	Immediate	Extreme weather, last resort
AI detection	Low	Consequence	Months	System-wide awareness

Table 2. Summary comparison of wildfire mitigation measures.

Financing matters as much as selection. Securitization, as required under SB 254, can lower the carrying cost of mitigation capital, while performance-based incentives can reward measured risk reduction rather than capital deployed. Utilities outside California should use the current window, before their first catastrophic event, to adopt approved plans that qualify for statutory protection, build internal risk-modeling capability, and secure the workforce that multi-year programs require.

The utilities that fare best in the next fire season will be those that can show, circuit by circuit, how much risk each dollar removed.

KEY TAKEAWAY



A defensible wildfire strategy is a ranked portfolio: operate protectively today, harden broadly, underground selectively, measure everything, and let risk per dollar decide.

Key Findings

Seven findings frame the path to a wildfire-resilient grid.

- Utility wildfire liability has produced one bankruptcy, multiple junk-grade downgrades, and multibillion-dollar exposures at PG&E, SCE, PacifiCorp, Hawaiian Electric, and Xcel.
- Power-line ignitions and fire-weather days are rising well beyond California, including in Texas, the Mountain West, the Plains, and the Southeast.
- California socializes catastrophic losses through a \$21 billion fund plus an up-to-\$18 billion continuation account; most other states instead tie liability protection to approved mitigation plans.
- Fast-trip protection settings have cut reportable ignitions on enabled lines by roughly 58 to 72 percent at low capital cost, but increase unplanned outages.
- Covered conductor reduces ignition risk by roughly two-thirds at about a quarter of the per-mile cost of undergrounding, and deploys two to three times faster.
- Undergrounding nearly eliminates segment ignition risk but at \$2 million to more than \$4 million per mile; it is best targeted at the highest-consequence corridors.
- A segment-level, risk-spend-efficiency framework that counts outage costs and co-benefits offers the most defensible basis for regulators, investors, and customers.

Method and Scope

This paper draws on utility wildfire mitigation plans and annual reports, CPUC and Office of Energy Infrastructure Safety decisions, state statutes, SEC filings, court records, rating-agency actions, and peer-reviewed and academic analyses published through September 2026. Figures are reported as published; the relative cost index in Figure 6 is illustrative.

Conclusion

Buying down the tail of wildfire risk, one circuit at a time

Wildfire has become the defining risk for a growing share of North American utilities. The financial consequences of a single ignition can exceed years of earnings, and the legal and insurance systems that once absorbed those losses are either under strain or being rewritten. Utilities can no longer treat mitigation as a compliance line item; it is now central to their credit quality, their license to operate, and their customers' trust.

The tools are proven and increasingly well understood. What separates leading programs is discipline in how those tools are combined: operational settings that act immediately, hardening at scale, undergrounding where it earns its cost, and data systems that make each decision measurable. Utilities that adopt a transparent, risk-based framework now, and build the workforce to execute it, will be best positioned to protect communities, keep rates defensible, and qualify for the liability protections that legislatures are increasingly willing to offer.

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