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Wildfire Safety Division

COMMENTS OF THE GREEN POWER INSTITUTE ON THE SDG&E 2026-2028 WILDFIRE MITIGATION PLAN

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The Green Power Institute (GPI), the renewable energy program of the Pacific Institute for Studies in Development, Environment, and Security, provides these *Comments of the Green Power Institute on the SDG&E 2026-2028 Wildfire Mitigation Plan*.

Introduction

The GPI performed a review of the San Diego Gas and Electric Co. (SDG&E) 2026-2028 base Wildfire Mitigation plan (WMP) with a focus on WMP policy design, Risk Methodology and Assessment (WMP Section 5), Wildfire Mitigation Strategy Development (WMP Section 6), Wildfire Mitigation Approaches (WMP Sections 8-9), and Integrated Distribution System Planning. Our comments focus on the distribution system, including risk modeling, risk model applications, mitigations selection, vegetation residue cradle-to-grave and cradle-to-cradle management, and integrated distribution system planning.[1] Our comments on PG&Es WMP that are identified as applicable to all IOUs and WMPs in general, apply here, though we try to avoid repeating them herein for efficiency's sake.

It is the role of the WMP to provide adequate justification and transparency necessary to evaluate the safety, reliability, and cost balance achieved by SDG&E's proposed methods and resulting scope of work for approval or modification via the GRC. SDG&Es combined amplification of wildfire consequence, treatment of PEDS and PSPS as interim mitigations, below average undergrounding cost estimates, decision to exclude return on equity within Benefit-Cost Ratios (BCR), among other design factors, combine to advance an undergrounding-first paradigm. Care should be taken to consider the combined effect of these WMP elements towards advancing a 12-year, undergrounding-focused mitigation portfolio.

[1] **OpenAI.** (2025). *ChatGPT (May 2025 version) [Large language model]*. Used for citation preparation and research assistance. Retrieved May 21, 2025, from https://chat.openai.com.

I. Risk Methodology and Assessment (WMP Section 5)

A. SDG&E should be ordered to provide adequate risk model documentation at a standard equivalent with other IOUs.

B. Risk-averse functions essentially establish a consequence sliding scale and modify the safety, reliability, affordability balance.

II. Wildfire Mitigation Strategy Development (WMP Section 6)

A. Lifecycle costs of undergrouding versus overhead hardening should be consistently defined across the IOUs and should include return on equity

B. SDG&E presents a robust mitigation scenario testing framework but fails to report alternative mitigation scenarios or mitigation selection risk tolerance thresholds.

C. SDG&E should report on total default undergrouding circuit miles based on its internally defined "extra heavy loading districts above 5,000' elevation."

D. Undergrouding plan forum shopping and regulatory alignment.

E. PSPS and PEDS risk reduction and mitigation effectiveness

III. Wildfire Mitigation Approaches (WMP Sections 8)

A. Improve DER program reporting and program design to ensure cost effective investments that mitigate near-term and long-term outage risk on hybrid overhead and underground hardened distribution systems.

B. Transition the Generator Assistance Program and Standby Power Program away from portable fuel generators to batteries.

C. SDG&E should endeavor to reduce the duration and scale of its PEDS outages and should consider sectionalizing as part of an overhead mitigation package.

D. Utilities should continue to exchange progress on and benchmark to overhead system risk mitigation methods, including IONA and Gridscope.

E. Deferring work orders based on planned undergrouding may result in otherwise avoidable risk accumulation over the next decade.

IV. Vegetation Management (Section 9)

A. Encourage SDG&E and all utilities to leverage investments in fuel treatment partnerships for matching fund opportunities.

B. SDG&E should be ordered to update its vegetation inspection pass rate to 95 percent.

C. Monitor the accrual of past due Vegetation Management work orders in the 181+ days bin

D. SDG&E and other utilities should develop wood and slash management program guidelines that support customer defensible space.

E. All utilities should develop sustainable wood and slash management targets that are transparent and trackable.

V. Integrated Distribution System Planning

A. Investigate ignition risk associated with peak summer loading and overloading risk.

B. Decade long, resource intensive WMPs are showing signs of slowing grid modernization and DER deployment.

Comments

Risk Methodology and Assessment (WMP Section 5)

SDG&E should be ordered to provide adequate risk model documentation at a standard equivalent with other IOUs.

SDG&E's updated planning risk model includes a Monte Carlo based framework for wildfire and Outage Program risk and a machine learning Probability of Ignition and Probability of Failure model. The model flow diagram offers a high-level summary of model inputs, but the documentation fails to provide any specifics on model construction, inputs, or validation. For example, the migration to an ML PoI/F model aligns with other IOU methodologies. However, ML models generally require large data sets which help improve model training and fit. SDG&E's WMP risk model description and Appendix B provide no information on the ML sub-models developed and their fit (AUC-ROC).

SDG&E's risk model documentation and descriptions are vague and lack transparency at a level far beneath current WMP planning risk model reporting standards and best practices. Models that lack validation metrics should not be approved for long-term wildfire mitigation selection applications that result in multi-billion-dollar ratepayer investments. While the OEIS-P-WMP_2025-SDGE-06 Data Request responses address some of the risk model documentation gaps, SDG&E should be required to provide an updated Appendix B that provides detailed information on par with other IOU risk model documentation and validation metrics for its new wildfire risk models.

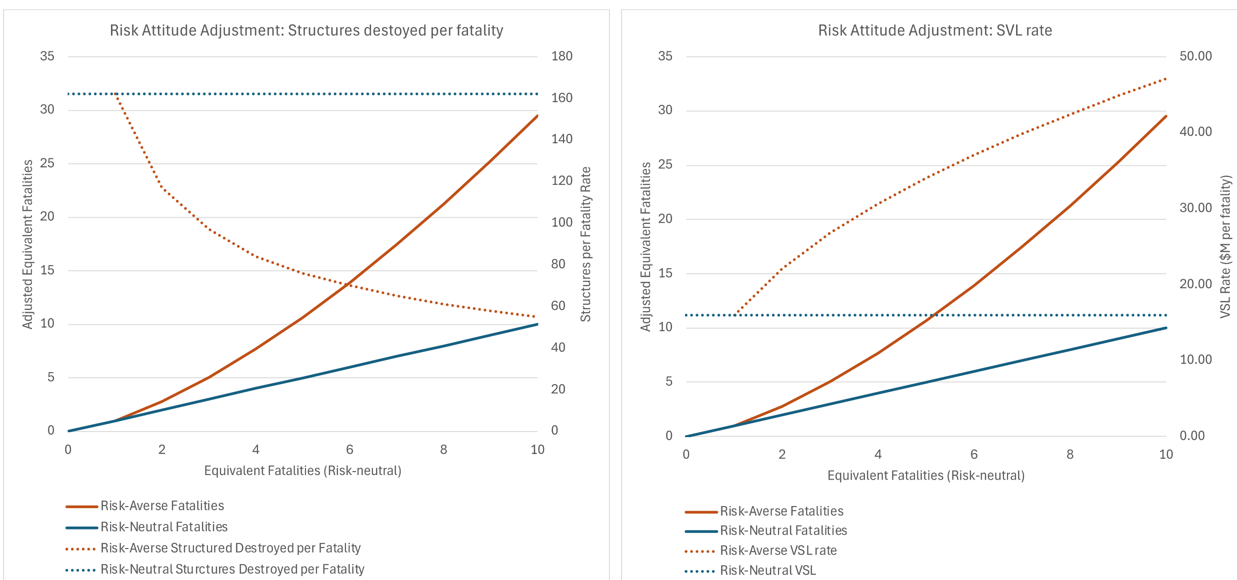
According to Appendix B Table – Detailed Model Documentation_5_23_25.xlsx, the data verification process is still in progress for all but two of the input datasets. SDG&E should report on its data verification timeline and how it plans to complete the data verification process. SDG&E should also report on whether and how it is addressing the lack of data verification while still applying its model to inform grid hardening mitigation investments.

Risk-averse functions essentially establish a consequence sliding scale and modify the safety, reliability, and affordability balance.

SDG&E applies risk-averse functions that amplify risk intended to reflect social cost versus a 1:1 risk-neutral cost. Consequence values have a substantive impact on granular risk scores which impact mitigation BCR. The greater the baseline risk value the larger the mitigation benefit, which in turn favors higher cost mitigations based on a BCR metric. A risk-neutral versus risk-averse approach modifies risk tolerance, the resulting mitigation portfolio, and therefore the resulting balance between safety, reliability, and cost.

SDG&E's risk-averse safety function pushes the portfolio selection in favor of safety considerations versus affordability. Amplifying the anticipated equivalent fatalities in the numerator of the BCR permits an increase in mitigation investment cost in the denominator, towards a BCR of 1. The safety risk-averse function can be conceptualized in terms of a sliding scale of fatalities per structure or Value of Statistical Life (VSL). SDG&E reports a Safety consequence value of 0.00617 fatalities per structure or 1 fatality per 162 structures destroyed, based on its assessment of CAL FIRE data.[2] SDG&E's adjusted equivalent fatalities risk-averse function can be thought of as modifying this conversion factor when predicted fatalities exceed 1—At 10 predicted fatalities, the effective risk-averse conversion rate becomes 1 fatality per 55 buildings destroyed (0.01822 fatalities per structure). Similarly, put into context of VSL, SDG&Es risk-neutral rate is $15.97M per predicted fatality (2025), while its risk-averse rate for 10 predicted fatalities essentially increases the VSL to $47.1M per predicted fatality. The Safety risk-averse function can be considered the same as adopting a sliding scale for consequence attribute valuation rates (Figure 1). SDG&E applies similar risk averse function to Reliability and Financial consequence attributes.

Figure 1. Risk-neutral and risk-averse consequence functions and effective sliding scales for structures per fatality or VSL.



Framing the risk-averse function relative to baseline consequence values puts it in context. As defined, VSL is the collective or average willingness to pay for a reduction in mortality risk. A sliding VSL scale raises questions as to whether it is appropriate to assume that Californias are willing to pay more for utility wildfire risk mitigations based on a VSL

[2] SDG&E 2026-2028 Wildfire Mitigation Plan, p. 38.

multiple times greater than its baseline value of $15.97M. Or whether it is appropriate to depart from CAL FIRE data informed fatality to building destruction ratios. This same question applies to SDG&E's Reliability and Financial attributes and risk-averse functions. Assuming a BCR >=1 qualifies as a cost-effective mitigation, a sliding scale that increases attribution risk value will also permit a concomitant increase in mitigation cost, or the cost ratepayers are willing to pay to mitigate the risk.

SDG&E's risk averse functions essentially build in a low risk-tolerance attitude that departs from CAL FIRE fatality data and baseline VSL, building cost, and value of outage minutes. The foundational questions that must be answered are whether the sliding valuation scales (1) reflect a ratepayer versus utility risk aversion attitude and/or (2) appropriately account for model uncertainty. The baseline VSL, building cost, and value of outage minutes reflect external studies and traceable data inputs (e.g. average structure cost, CAL FIRE database, Technosylva simulations) that are more readily defendable as ratepayer incurred costs and risk attitude. In contrast, SDG&E's elective risk-averse scaling factor is at least partially informed by utility risk attitude.

Utilities have many quantitative and qualitative pathways to modify risk valuation, BCR, and/or final mitigation selections. Many methods include subjectivity that can be invoked, for example, to hedge against risk model uncertainty and/or reflect utility risk tolerance. GPI generally supports risk modelling methods that offer transparent risk-neutral results and BCR that can be applied along with other transparent considerations such as residual risk. We encourage OEIS to benchmark with CPUC decisions and proceedings whether SDG&E's risk-averse functions are in alignment with ratepayers' risk attitude and best interests for balancing safety, reliability, and affordability.

Differences between utility wildfire consequence planning model design and scaling factors are likely to result in deviations between ratepayer outcomes in terms of balancing safety, reliability, and cost. For example, PG&E's WFC consequence model is essentially ignition focused – it does not consider consequence as a function of nearby structures that are potentially in the pathway of a utility ignited wildfire. PG&E flattens, and elevates relative risk ranked circuit segment consequences through a variety of methods and converts its relative consequence values based on an enterprise risk model conversion factor. GPI strongly recommends conducting a comprehensive comparison of utility consequence models and assumptions to ascertain whether ratepayers across California are subject to similar risk tolerances and resulting mitigation solutions and costs. This is critical to ratepayer equity and downstream scope of work approval via the GRC.

Wildfire Mitigation Strategy Development (WMP Section 6)

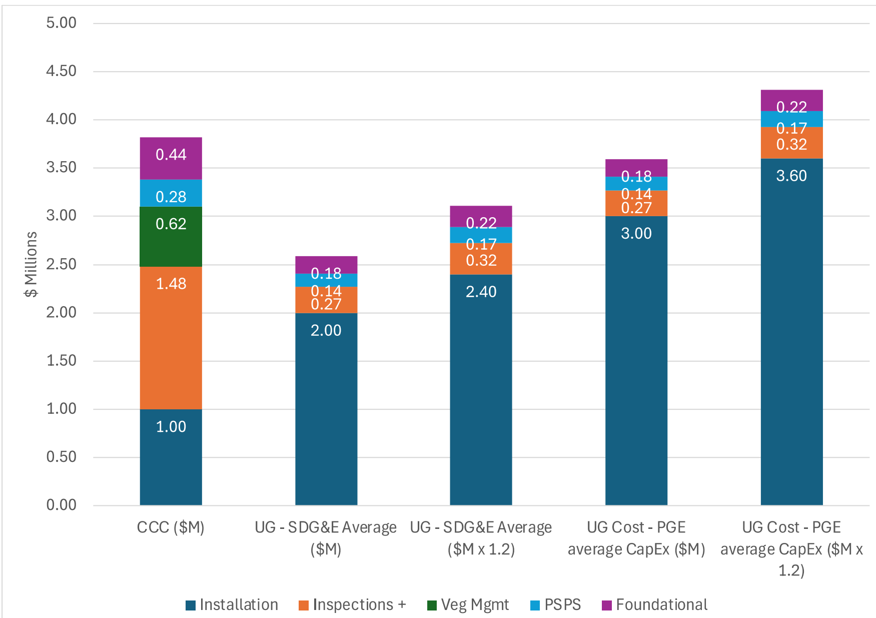
Lifecycle costs of undergrounding versus overhead hardening should be consistently defined across the IOUs and should include return on equity

SDG&E provided a 55-year, per mile lifecycle cost analysis of Combined Covered Conductor and Undergrounding in its WMP Workshop presentation. The analysis is applied in its BCR calculation which informs its mitigation selection and shift to an Undergrounding focus. In general, the grid hardening lifecycle cost assessment is an advancement that has been long awaited in the WMP towards a comprehensive assessment of the cost-benefits of an overhead versus undergrounded hardened system. However, issues remain including general reporting choices, unprecedented low capital costs, missing return on equity costs, and inconsistency between IOU methods.

SDG&E's CCC versus Undergrounding per mile figure, presented in the WMP Workshop, was not included in the WMP. While these values can be somewhat discerned from SDG&E's WMP Appendix G, the figure should have been, and should now be, included in the WMP—this is a foundational input that determines BCR and provides BCR calculation transparency. The cost comparison figure also chooses to leave out the 120% overhead to undergrounding correction factor for the conversion of 1 mile of overhead system to approximately 1.2 miles of undergrounding (Figure 1).

SDG&E's lifecycle costs for undergrounding raise questions about accuracy. The projected CapEx average of $2 Million per mile undergrounding cost is two thirds that of PG&E. Applying the distribution system expansion factor for overhead to undergrounding (x1.2) and increasing the average installation cost to PG&E's $3M estimate would increase the cost of undergrounding above SDG&E's CCC lifecycle cost. SDG&E's HFTD territory includes watersheds, vegetation coverage, bedrock exposure, steep terrain, and faults, all of which the Utilities identify as challenges that can increase undergrounding cost. SDG&E should be required to provide additional data substantiating that it can achieve an average undergrounding installation cost that is much lower than the other IOUs.

Figure 1. SDG&E Reported CCC and Undergrounding costs, adjusted to include a 1.2 overhead to undergrounding factor and showing cost adjustments based on PG&E's average Undergrounding CapEx cost.



SDG&E's UG lifetime costs do not include any vegetation management O&M costs, which is suspect since SDG&E's own public outreach materials refer to required VM work for undergrounded infrastructure.[3] Other utilities offer more transparent VM standards for undergrounded electric lines and pad mounted equipment, including a 3' and 10' clearance from pad mounted equipment and the service doors, respectively, and "right tree, right

[3] **San Diego Gas & Electric.** (n.d.). *Vegetation Management Brochure*. Retrieved June 11, 2025, from https://www.sdge.com/sites/default/files/FINAL_S1870096_VegMgmtBro.pdf .

place" considerations.[4,5] GPI has previously raised concerns about future vegetation management work along Undergrounded lines, which remains absent from the WMPs. The WMP, which now requires the use of BCR, must include accurate mitigation costs to best inform mitigation selection in ratepayers best interests via portfolio approval or modification through the GRC. All IOUs, including SDG&E should be required to report on its VM protocols for undergrounded lines, and include the cost in a life-cycle cost assessment as an input to BCR.

Inspection+ costs include asset repairs. It is generally understood that while undergrounded distribution lines have fewer outages, the repairs typically take longer and are more costly compared to overhead lines.[e.g.6] SDG&E also includes PSPS costs in its undergrounding cost stack at half the rate of costs associated with CCC hardening. It is concerning that SDG&E anticipates only a halving of PSPS costs with its strategic undergrounding plan. This PSPS cost also appears to conflict with its WMP narration which "assumes a 99% reduction of wildfire and PSPS risk upon deployment."[7] SDG&E's reported average PSPS costs, Inspection+ cost source, and historic undergrounding inspection and repair costs should be explored in more depth for the purpose of comparison to CCC costs and other utility's UG costs.

All utilities should be required to include return on equity costs within the mitigation cost quantification. PG&E appeared to include the return in equity costs in their CBR quantification (emphasis added):

> Additionally, for capital projects, a Present Value of Revenue Requirement (PVRR) multiplier is applied to the NPV cost for a project. This is a financial measure that has traditionally been used by public utilities subject to cost-of-service regulation. PVRR

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[4] **FirstEnergy Corp.** (n.d.). *Distribution Vegetation Management Brochure*. Retrieved from https://www.firstenergycorp.com/content/dam/customer/get-help/files/trees/distribution-veg-mgmt-brochure.pdf.
[5] **Safe Electricity.** (n.d.). *Planting the right tree in the right place*. Retrieved June 11, 2025, from https://safeelectricity.org/safety-tips/planting-right-tree-right-place.
[6] **Power Delivery Intelligence Initiative (PDI²).** (2021, March). *Underground vs. Overhead Electric Distribution Systems: A Comparison of Reliability and Maintenance*. Retrieved from https://pdi2.org/images/uploads/2021/03/130-SC-SCANA-Undergroundvs1.pdf.
[7] SDG&E 2026-2028 Wildfire Mitigation Plan, p. 113.

> represents the present value of revenue that must be collected from customers to pay for all the costs (net of benefits) incurred on a project*, including a fair and reasonable rate of return on investment*, over the life of the project.[8]

Ratepayers incur a utility rate of return on capital cost that increases the cost above what a utility pays to complete the work. SDG&E does not appear to include this return on equity cost in its CCC versus Undergrounding cost figure or BCR quantification. Failure to include the return on equity costs that ratepayers will incur more closely approximates the BCR of the Utility not the BCR to the ratepayer. The BCR to the utility includes the net benefit dollar value of avoided risk events plus return on equity. For example, if SDG&E achieves a BCR of 1 with an undergrounding project based on its current accounting method, the utility and ratepayers avoid the cost of the risk events, transfers those costs to the ratepayer in the form of the mitigation life-cycle cost, and makes a net profit on the ratepayer through return on equity—meaning the ratepayer costs exceed the anticipated cost of avoided risk events. Utility net profit per hardened mile increases with higher per unit capital cost and system expansion. Including the return on equity within the mitigation cost reflects a BCR to the ratepayer, who pays both the cost of the mitigation plus return on equity costs to the utility. All utilities should be required to include return on equity with their cost-benefit ratio. Inconsistencies in the qualification method will contribute to disparate risk mitigation outcomes across California.

With the advent of the BRC as a mitigation selection metric, mitigation package cost is now a foundational metric for planning risk model application in the WMP. The methods should be aligned across utilities. All IOUs should be required to develop lifecycle UG versus overhead system hardening cost assessments. PG&E alludes to long-term costs savings from UG but fails to provide the analysis. Gaps in agency guidance will be filled by utility preferred methods. Waiting to align the cost quantification method will only perpetuate and entrench divergent methods across the IOUs. Consistent methods are a question of California ratepayer equity. Deviations between utility foundational cost assessment methods will further obfuscate whether equity is being achieved across California in terms

[8] Ibid p. 155.

of wildfire risk mitigation portfolios that balance ratepayer's safety, reliability, and cost. GPI recommends requiring the IOUs to develop a joint mitigation package cost quantification method that expands on SDG&E's lifecycle cost assessment.

SDG&E presents a robust mitigation scenario testing framework but fails to report alternative mitigation scenarios or mitigation selection risk tolerance thresholds.

SDG&E describes a risk model framework that allows it to test sensitivity to various inputs and develop multiple mitigation package scenarios with outcome metrics such as total cost and risk reduction, as well as granular considerations including upstream PSPS risk.[9] GPI commends SDG&E for developing these capabilities. However, the WMP fails to proffer any alternative mitigation portfolios as a comparison. It also does not report on how it applies the planning model output including if it considered any quantitative BCR, risk exposure, or residual risk thresholds that inform mitigation selection. The WMP only states:

> Currently, CBA outputs from WiNGS-Planning are used to determine investment mitigations that reduce risk. Although the risk reduction targets are often aimed at cost effectiveness, annual performance objectives, mileage targets, and other limitations and constraints are also considered to inform investment decisions…
>
> CBRs are incorporated into the WiNGS-Planning decision-making process to maximize risk reduction and optimize resources. The WiNGS-Planning model selects the more efficient use of funding and resource allocation to focus mitigation deployment on wildfire risk reduction.[10]

The quantitative and qualitative basis upon which it arrived at its 2026-2028 granular undergrounding versus covered conductor plan and longer-term 100% undergrounding plan is not transparent. SDG&E should at a minimum provide additional transparency into its mitigation selection decision making framework and any quantitative thresholds it applies. SDG&E should also provide alternative mitigation portfolio scenarios and scenario metrics along with a detailed explanation of why it has determined that the alternative portfolio(s) is sub-optimal.

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[9] Ibid, p. 96-97.
[10] Ibid, p. 97.

SDG&E should report on total default undergrounding circuit miles based on its internally defined "extra heavy loading districts above 5,000' elevation."

SDG&E states:

> …in extra heavy loading districts above 5,000 feet, covered conductors cannot be installed and therefore a strategic undergrounding solution would need to be selected. Standards also dictate available cable and conductor sizes.[11]

BVES and Liberty service territories are both subject to high snow and ice loading and are entirely located at elevations of 5,000-9,000'+, reaching highs in the 80-90s which contribute to lower air density. Both BVES and Liberty have largely focused their mitigation plans on overhead mitigation packages that utilize covered conductor. It may be prudent to benchmark heavy loading and utility-specific extra heavy loading standards with the HFTD between utilities. SDG&E's "extra heavy load districts above 5,000'" are an internal design standard that exceed GO 95.[12] SDG&E should report on the internal environmental standards for extra heavy load districts above 5,000', the total number of distribution system circuit miles in the HFTD that are within its extra heavy loading districts, and if/how this design standard modifies mitigation selections informed by its planning model. This will improve transparency into the mitigation selection process and resulting mitigation portfolio.

Undergrounding plan forum shopping and regulatory alignment.

SDG&E reports that its 2024 GRC regulates system undergrounding targets through 2027. For its 2028 undergrounding plans it will either implement its preferred mitigation portfolio via an EUP under SB884 or the GRC.[13] OEIS should be weary that this mitigation work scope approval plan, optionally based on two different regulatory pathways, appears to invoke forum shopping—a tactic where a utility may choose the regulatory pathway most favorable to its preferred outcome. Regulatory alignment between OEIS and CPUC as well as the GRC, EUP, and WMP processes will be critical to ensure a grid hardening outcome

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[11] Ibid, p. 102.
[12] SDG&E 2020 OVERHEAD CONSTRUCTION STANDARDS. https://www.sdge.com/sites/default/files/OHCSe%20%281%29.pdf.
[13] SDG&E 2026-2028 WMP, p. 109.

that equivalently balances safety, reliability, and affordability, regardless of which forum results in final scope of work approval.

PSPS and PEDS risk reduction and mitigation effectiveness

SDG&E's interim mitigations include PEDS, PSPS events, and sectionalizing to reduce outage program impacts.[14] However, the proposed 12-year grid hardening work plan will still rely on "PSPS and situational awareness" to provide 25% of total wildfire risk reduction in 2037.[15] Long-term, residual PSPS and PEDS risk exposure is at least in part a function of distribution system design, including the location of CCC, UG, sectionalizing investments, DER deployment, and microgrids. Balancing mitigation portfolio safety, reliability, and cost requires the ability to model both granular PSPS+PEDS wildfire risk reduction value and residual outage risk as a function of hybrid overhead and undergrounded distribution system mitigation portfolios.

SDG&E's planning model refers to a capability that adjusts PSPS risk as a function of upstream mitigations.[16] CCC outage risk reduction effectiveness is not quantified, but risk reduction is estimated in the planning model by simulating a higher deenergization wind gust threshold. SDG&E only calculates Activity Effectiveness - Outage Program Risk for undergrounding (99%) and microgrids (100%).[17] However, undergrounding a given circuit segment does not guarantee PSPS or even PEDS outage event risk elimination in a hybrid overhead and undergrounded system. GPI is concerned that assuming a 99 percent outage program risk mitigation effectiveness for undergrounding is predicated on adopting a 100% undergrounding approach to risk mitigation. We are also concerned that SDG&E does not have a method to determine the outage program risk reduction value of sectionalizing and DER deployment (i.e. batteries and hybrid solar plus batteries) and that it does not include these mitigations as well as PEDS+PSPS as part an overhead mitigation package. SDG&E should be ordered to address these outage risk mitigation quantification gaps.

[14] Ibid, p. 117-118.
[15] Ibid, p. 110.
[16] Ibid, p. 96.
[17] Ibid, p. 111-113.

PEDS and PSPS are already slated as long-term wildfire risk mitigation tools. Failure to consider their wildfire risk mitigation effectiveness as part of an overhead hardened system that includes outage risk mitigations (e.g. sectionalizing and DER) only serves to advance an undergrounding-first paradigm versus an optimized hybrid overhead and undergrounding mitigation portfolio. SDG&E should develop more robust long-term PEDS+PSPS wildfire risk reduction and outage program risk mitigation assessment capabilities that inform hybrid mitigation portfolio designs.

Wildfire Mitigation Approaches (WMP Sections 8)

Improve DER program reporting and program design to ensure cost effective investments that mitigate near-term and long-term outage risk on hybrid overhead and underground hardened distribution systems.

As SDG&E's grid hardening efforts progress and adapt to GRC work scope approvals, PSPS and PEDS will continue to serve an important role in wildfire risk mitigation. With proposed grid hardening plans now stretching through the next decade it is becoming clear that the outage impacts from these operational mitigations should be expected for the foreseeable future. SDG&E anticipates that outage programs will provide 25 percent of wildfire risk reduction by 2037, after its proposed grid hardening plan is completed, which largely focuses on undergrounding. Continuing to advertise PSPS and PEDS risk as an "interim" mitigation will hinder long-term solutions to the associated reliability risk. Operational mitigation outage risk can and should be proactively addressed through holistic overhead system solutions that include DER such as behind the meter and front of meter batteries and hybrid solar plus battery systems.

SDG&E's three planned resiliency programs are the Standby Power Program (SPP), the Customized Resiliency Assessments (CRA), and the Generator Assistance Program (GAP). While SDGE reported these programs in Section 8, they are identified as having qualitative targets to provide backup power at "priority sites."[18] The CRA program assesses customer backup power needs and potential permanent or temporary backup power solutions, as well

[18] P. 127.

as providing information and referring customers to its other backup power programs. The SPP program focuses on serving non-residential customers and offers backup power solutions including permanent generators and batteries plus solar solutions "depending on site requirements, feasibly, and costs." GAP offers rebates on portable backup power options to HFTD customers that have experienced at least one PSPS.

SDG&E reports that between 2019-2024 it has supported 9,641 customers with backup power during PSPS outage events. Attachment A offers some data on Generator and Backup battery program impacts. Upwards of 5,600 and 2,600 customers, respectively, have received support from the Generator Grant Program (GGP) and Generator Assistance Program (GAP) programs to date. In 2024, the GGP and GAP deployed 158 and 232 units, respectively.

The WMP also references the Self-generation Incentive Program (SGIP) and Microgrid Incentive Program in attachments. These are integrated distribution system planning programs, initiated by the CPUC outside of the WMP, that are geared towards addressing outage risk associated with wildfire mitigations within the HFTD. There is no reason to exclude or marginalize these programs from the WMP as they constitute ratepayer investments in activities that address WMP outrage program risk.

It remains unclear the total number of customers that have received temporary backup power support (e.g. event specific) versus portable energy supplies or permanent backup power installations, and through which of SDG&Es WMP and CPUC DER programs. It is also unknown how many customers still experience sustained wildfire mitigation-related outages but have yet to secure backup power. Reporting gaps make it impossible to know the extent to which past and future PSPS and PEDS outage risk has and will be mitigated through DER deployment programs. This not only raises questions about the ongoing impacts to customer reliability in the near term, but also SDG&E's ability to mitigate the consequences of its anticipated long-term reliance on outage programs to manage wildfire risk *after* deploying a 12-year hybrid overhead and undergrounded grid hardening plan.

Targets and planned improvements for each of SDG&E's reliability programs, excluding SGIP and MIP, are purportedly in OEIS Table 8-1, though the table provides no targets.[19] The lack of quantitative targets for DER programs prevents transparency into the extent to which these programs are making an impact on customer reliability risk due to PSPS and PEDS outage events. Missing data on the types of backup power deployed, whether event specific, portable, or permanent, prevent an understanding of whether these programs are efficient and effective at mitigating near-term and long-term PSPS and PEDS outage risk. For example, event specific backup power only offers one time reliability support and must be coordinated by SDG&E for each event. Portable units may be smaller, offer shorter ride through capabilities, and may only power individual plug in devices such as medical devices, phones, or appliances. Permanent DER installations, including batteries and hybrid solar plus battery systems can offer whole house power or be configured to power critical circuits.

Each of these backup power solutions have different potential PSPS and PEDS risk mitigation value based on power supply, permanence, and customer type (e.g. AFN, critical facilities etc.). Strategic deployment in alignment with granular outage program risk anticipated for near-, mid-, and long-term WMP planning horizons can ensure these reliability programs are right sized, timely implemented, and the specific solutions fit customer needs today and in the future. For example, it would be imprudent to invest in a temporary or portable backup power supply for a customer that is at risk of experiencing PSPS and PEDS outages through 2037+ based on the utility grid hardening plan. It would also be less efficient to deploy a permanent hybrid battery plus solar solution at a residence that is expected to experience few to no outage events over the long-term due to near-term overhead or undergrounding plans and/or local conditions. Efficiently minimizing PSPS and PEDS outage consequences over the near-, mid-, and long-term planning horizons, requires knowing where outages are most likely to occur before and after grid hardening mitigations (i.e. granular outage risk), how long they are expected to last, and a coordinated grid hardening and DER deployment plan that addresses risk over all timescales.

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[19] P. 146-7, 127.

SDG&E should be required to improve outage risk forecasting for all planning horizons, as well as DER program reporting and design to maximize DER deployment BCR. At a minimum this must start with improved DER program reporting. The WMP should include how much PSPS and PEDS risk is already mitigated through backup power, including the types of backup power and the specific customer types already supported.[20] SDG&E should provide reliability program targets including the types of DER it will offer and quantitative unit targets (e.g. rebate vouchers, installations etc.). Programs should identify the populations it aims to serve (e.g. AFN impacted by 3 or more PSPS), the risk reduction impact the program targets are anticipated to provide, and how backup power supplies are strategically deployed to mitigate near and long-term WMP outage program risk. Improvements should include developing BCR for behind the meter as well as front of meter DER. A DER BCR should be applied to inform mitigation portfolio design and integrated distribution system planning within and beyond the WMP. The backup power programs within scope for WMP reporting should include utility elective programs plus existing DER programs at the CPUC (e.g. SGIP, MIP).

Mitigation portfolios that balance safety, reliability, and cost must employ an integrated system planning paradigm that includes leveraging the outage ride-through capabilities of DER and microgrids as part of a hybrid overhead and undergrounded distribution system. Is it not in ratepayers best interest to marginalize DER programs and their role in hybrid overhead and undergrounding mitigation portfolios as solutions to short- and long-term outage program risk.

Transition the Generator Assistance Program and Standby Power Program away from portable fuel generators to batteries.

SDG&E's Generator Assistance Program (GAP) provides rebates on portable fuel generators and power stations.[21] The SPP also cites the deployment of permanent standby generators in

[20] Different customer types have safety risk weights ranging from 1-20, such that targeted DER programs will have varying impacts on outage risk reduction. These values should be reported in the WMP model documentation narrations for improved transparency. See: SDG&E_2026-2028_Base-WMP_Appendix G Supporting Data_Errata.xlsx, Tab: Microgrid Assumptions.
[21] Ibid, p. 148.

addition to battery solutions. Executive Order N-79-20 and AB 1346 addresses Small Off-Road Engines (SORE) which include generators, setting targets that require these generators to meet more stringent emission standards by 2024 and zero-emission standards by 2028.[22,23] In accordance with California emission reduction goals and SORE regulation, SDG&E should be ordered to revise its DER programs to eliminate fuel generators and to instead transition to zero-emission DER by no later than 2028.

SDG&E should endeavor to reduce the duration and scale of its PEDS outages and should consider sectionalizing as part of an overhead mitigation package.

SDG&E's extended PEDS outage events suggest negative impacts of avoiding proactive sectionalizing in difference to its undergrounding plans. SDG&E's top-10 circuits impacted by SRP and SGF in the past 3 years shows average circuit outage durations ranging from 1.1 to 16.8 hours (Cumulative outage duration (h)/number of outages).[24] The average outage duration in the top-10 circuits is ~7 h (Total cumulative outage duration (h)/ total outages). Only three of the top 10 circuits impacted by SRP and SGF experienced outages 2 or more times in the past 3 years, suggesting relatively infrequent customer impacts that are exacerbated by long reenergization times. The outage frequency for automatic recloser PEDS is higher (2-17 events per circuit) and have a similar average outage duration of ~6 h. PG&E's achieved an EPSS Customer Average Interruption Duration Index (CAIDI) of 150 minutes in 2024.[25] SDG&E should be ordered to assess operational and overhead grid hardening approaches that will reduce PEDS outage duration and scale and/or report on how grid hardening prioritization will mitigate PEDS and PSPS risk in the near-term (1-3 years).

SDG&E's sectionalizing approach is directly linked to its undergrounding plans and therefore biases towards its preference for undergrounding. The approach focuses on installing switches on undergrounded circuits and precludes switch installations on overhead

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[22] California Air Resources Board. (2024, January). *Zero-emission off-road equipment executive order fact sheet*. https://ww2.arb.ca.gov/sites/default/files/2024-01/ZEV_EO_Off-Road_Fact_Sheet.pdf.
[23] California Air Resources Board. (n.d.). 2021 Assembly Bill 1346 (Berman, Marc): Small off-road engines – Chaptered. https://ww2.arb.ca.gov/2021-assembly-bill-1346-berman-marc-small-road-engines-chaptered.
[24] Ibid, p. 194-6.
[25] PGE 2026-2028 WMP, p. 328.

circuits slated for undergrounding.[26] The decision to preclude sectionalizing efforts where it intends to install undergrounding could sustain, versus mitigate, the scale and duration of PEDS and PSPS outage events over its 12-year grid hardening work plan.

The Combined Covered Conductor program also does not appear to include sectionalizing.[27] Sectionalizing is generally a high BCR PSPS and PEDS risk mitigation approach that is typically part of an overhead system mitigation package. Choosing to not implement this mitigation, or failure to include it as part of an overhead mitigation package, may result in extended, heightened PEDS and PSPS risk exposure for the foreseeable future on SDG&E's system as it advances a decade long undergrounding plan.

In its sectionalizing program description, the WMP states "For these reasons, SDG&E is unable to determine Outage Program risk reduction." Its mitigation strategy suggests that it does not have a way to assess the outage risk reduction impacts of sectionalizing on existing hardened overhead lines or as part of an overhead system mitigation package. This WMP design element reinforces undergrounding as the only pathway to reduce Outage Program risk. This also extends to an inability to assess Outage Program risk reduction for a hybrid overhead and underground system.

Sectionalizing on undergrounded circuit segments and precluding sectionalizing based on future undergrouding plans versus including it as part of an overhead mitigation undermines the PEDS+PSPS risk reduction as well as BCR of this mitigation activity. SDG&E should be ordered to assess whether its sectionalization deferral approach based on undergrounding is preserving PEDS and PSPS outage risk on its system and whether additional overhead system sectionalizing could reduce PEDS and PSPS risk. SDG&E should also be ordered to develop the capability to evaluate Outage Program risk reduction for an overhead mitigation package that includes sectionalizing. This capability is critical for assessing the cost-benefit and total risk reduction of a hybrid overhead and undergrounded system.

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[26] SDG&E 2026-2028 WMP, p. 145.
[27] Ibid, p. 131.

Utilities should continue to exchange progress on and benchmark to overhead system risk mitigation methods, including IONA and Gridscope.

PG&E reported on a promising new transformer inspection method (IONA) and real-time grid monitoring capabilities (Gridscope). SDG&E should benchmark to PG&E's IONA and Gridscope overhead system health monitoring and risk mitigation approaches. These risk monitoring and inspection approaches compliment an overhead system mitigation package that is relevant to assessing the cost-benefits of a hybrid overhead and undergrounding approach, as well as bolstering risk mitigation on existing and planned cover conductor hardened overhead lines. WMP must be able to evaluate the cost-benefits of hybrid overhead and undergrounded systems. In addition, undergrounding plans should not preclude progress on overhead system design improvements.

Deferring work orders based on planned undergrounding may result in otherwise avoidable risk accumulation over the next decade.

SDG&E's open work order deferral criteria include considerations as to whether the work is within the scope of its Strategic Undergrounding Program.[28] By 2028 most HFTD circuit mile hardening is within the SUP, and from 2032-2037 all hardening work is within the SUP. GPI is concerned that SDG&E's decision to delay work order closures in the name of "efficiency" around its SUP will result in unmitigated overhead system risk, possibly for years. SDG&E should be ordered to provide details on how long open work orders will be permitted to go unresolved on account of coordination with its SUP and how it will timely resolve unmitigated risk associated with these open work orders. This should include how SDG&E treats open work orders located on circuit miles slated for undergrounding in near-term (1-3 year), mid-term (4-6 year), and long-term (7-10 year) planning years of the SUP.

[28] SDG&E 2026-2028 WMP, p. 192.

Vegetation Management (Section 9)

Encourage SDG&E and all utilities to leverage investments in fuel treatment partnerships for matching fund opportunities.

SDG&E reports on several vegetation management partnerships with community organizations that involve defensible space and fuels treatments.[29] SDG&E's investments include fuel break maintenance efforts in partnership with the Campo Band of Diegueno Mission Indians. This work is described as addressing risk to transmission towers and the reservation. GPI is supportive of fuel management maintenance work that sustains the benefits of existing fuel management areas and generally supports SDG&Es fuel management partnership efforts overall. We additionally commend SDG&E for reporting on the costs associated with each of its partnerships. The total cost of fuels management partnerships in 2023 was approximately $1.36M, or less than its estimated lifetime O&M costs of 1 mile of hardened distribution overhead lines.

Towards continued improvements, GPI suggests that SDG&E benchmark with PG&E regarding community partnership investment matching opportunities. Utility investments in community informed wildfire risk mitigation efforts can and should be leveraged to secure matching funds that amplify the wildfire risk mitigation impact when possible. Matching funds and the additional effort invested to secure them can offer a high return on investment that benefits wildfire risk reduction associated with a wide range of drivers, including utility ignited wildfires and received risk. Utilities that engage in fuels management activities should also consider the sustainability of each project, such as SDG&E's fuel break maintenance partnership.

SDG&E should be ordered to update its vegetation inspection pass rate to 95 percent.

SDG&E reports an annual pass rate target of 90 percent for its 2026-2028 Vegetation Management QA and QC Activity Targets.[30] In RN-PG&E-23-02, PG&E was ordered to update its 2025 VM QA and QC program pass rate targets to 95 percent or to establish an

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[29] Ibid, p. 216.
[30] Ibid, p. 224.

improvement program that achieves 95 percent pass rate by 2025.[31] Planning standards such as QA and QC program target pass rates should be applied universally across utilities. GPI recommends requiring SDG&E to update its VM QA and QC Activity Target pass rate to 95 percent, consistent with past OEIS orders.

Monitor the accrual of past due Vegetation Management work orders in the 181+ days bin

SDG&E reports that it expects its future work orders to remain consistent with the historical 5-year average. Its past due vegetation management work orders decline with duration past due, suggesting eventual closure, typically by 90+ past the planned remediation date. However, a comparison to their 2023-2025 WMP shows that Vegetation Management past due work orders have increased across all tracked timeframes in the HFTD (Table 1).

Table 1. Past due vegetation management work orders since the 2023-2025 WMP. Sources: SDGE 2023 WMP R2-1 (6/7/2024), p. 285; 2026-2028 SDGE WMP p. 228.

WMP Plan year	HFTD Tier	0-30 Days	31-90 Days	91-180 Days	181+ Days
2023-2025	HFTD Tier 2	79	533	4	2
2026-2028	HFTD Tier 2	2,514	3,601	53	70
Total Change		2,435	3,068	49	68
2023-2025	HFTD Tier 3	357	20	5	1
2026-2028	HFTD Tier 3	790	2,475	411	2
Total Change		433	2,455	406	1

Increases in vegetation management past due work orders since the 2023-2025 WMP could be the result of multiple drivers. SDG&E should assess the drivers of these increases and whether its current vegetation management program is equipped to mitigate the further accumulation of delayed open tags in the HFTD (e.g. workforce, increased tree mortality, etc.). We further suggest tracking the accrual of past due work orders in all bins over the course of the 2026-2028 WMP, but especially the 181+ day past due bin which indicates persistent unresolved open work tags. Year-over-year increases in past due work orders over time can indicate a capacity deficit or methodological gaps that if not addressed could lead to the accumulation of vegetation risk in the HFTD.

[31] 2024 04 02 PGE's_20232025_Wildfire_Mitigation_Plan_Revision_5__Redlined, p. xii.

SDG&E and other utilities should develop wood and slash management program guidelines that support customer defensible space.

SDG&E reports the removal of Vegetation debris in association with IVM fuels management unless it is used as ground cover or at the property owner's request, as well as general chip onsite and/or remove practices for other VM activities. There is no mention of vegetation residue management practices aimed at supporting customer defensible space within the WMP or referenced Program Overview Guide; Version November 1, 2024. Responsible management of fuels created by vegetation management, including ROW pruning and removal, should continue to evolve in accordance with defensible space laws and CAL FIRE guidelines.

All utilities should develop sustainable wood and slash management targets that are transparent and trackable.

SDG&E identifies a qualitative target for wood and slash management sustainability that includes exploring "additional options of diverting green waste from landfills to recycling facilities." GPI reported on SDG&E's green waste diversion successes in our 2023 VM residue assessment, identifying SDG&E as a leader in sustainable green waste recycling versus disposal.[32] SDG&E's wood and slash management sustainability target is a highly marginalized component of their WMP, making tracking a challenge. Regardless, their ongoing VM recycling efforts and sustainability goals are commendable as is their voluntary, albeit vague, reporting within the WMP. SDG&E's methods and internal goals should be recognized and benchmarked with other utility practices through formalized reporting requirements within the WMP.

The ongoing lack of a WMP reporting requirement continues to make benchmarking sustainable VM residue methods, best practices, and utility-specific progress a largely overlooked aspect of the WMPs. We build on our prior 5+ years of advocacy for transparent VM residue management practices that mitigate the accumulation of fuels within the HFTD and that divert the resulting organic products from landfills in accordance with state goals.

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[32] GPI Comments on the 2023-2025 WMPs, p. 16.

CalRecycle reports that organic waste in landfills emits 20 percent of California's methane, a potent greenhouse gas. AB-1826 Solid waste: organic waste (2013-2014) requires businesses to arrange for organic waste recycling, including for prunings, trimmings, and untreated wood waste, with exemptions for businesses in rural jurisdictions.[33] SB-1383 Short-lived climate pollutants: methane emissions: dairy and livestock: organic waste: landfills (2015-2016) tasked CARB with reducing methane by 40 percent below 2013 levels by 2030 and a 50 percent and 75 percent reduction in statewide disposal of organic waste from 2014 levels by 2020 and 2025, respectively.[34] The CARB 2022 Scoping Plan calls for the "diversion of organics from landfills" and states that "Near-term diversion efforts are critical to avoid locking in future landfill methane emissions." [35] The 2022 Scoping Plan directs that "State agencies also should use the Scoping Plan to review and update their own programs and policies to support the actions identified in this Scoping Plan."[36] In 2022 the CPUC established renewable biomethane gas procurement targets that "will reduce otherwise uncontrolled methane and black carbon emissions in our waste, landfill, agricultural, and forest management sectors.[37,38] OEIS, a state agency, should review and update the WMP requirements to incorporate methane emission reduction considerations through organic waste diversion, consistent with state goals and CARB 2022 Scoping Plan findings.

To put the issue in perspective, PG&E reported that 151,033 tons of removed vegetation management residues passed through their contracted wood yards in 2021. CalRecycle reported pruning and trimmings as the 9th most prevalent material waste type in California in 2021 (2.8% of total), equating to an estimated 1.3M tons.[39] If all of PG&E's VM residue tonnage tracked through wood yards in 2021 was disposed of in California landfills, this

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[33] AB 1826 Solid waste: organic waste.
[34] SB 1383 Short-lived climate pollutants: methane emissions: dairy and livestock: organic waste: landfills.
[35] California Air Resources Board. (2022). *2022 Scoping Plan for achieving carbon neutrality*. p. 35, p. 233 https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.
[36] Ibid, p. 35.
[37] Ibid, p. 233.
[38] California Public Utilities Commission. (n.d.). *CPUC sets biomethane targets for utilities*. https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-sets-biomethane-targets-for-utilities.
[39] CalRecycle. (2021). *Disposal facility-based characterization of solid waste in California (Revised)*. California Department of Resources Recycling and Recovery. p. 11 https://www.calrecycle.ca.gov/.

would amount to approximately 11 percent of the total pruning and trimmings disposed of across the state in 2021. VM residues are an annual source of utility generated organic waste, of which a portion is diverted to landfills where slow decomposition creates a long-term source of methane emissions.

State policy requiring commercial businesses to recycle their organic waste include rural jurisdiction exemptions, presumably on the assumption that these areas generate less organic waste overall. Whether these exemptions apply to utility VM contractors should be considered. If utility VM contractors evade organic waste reporting requirements through rural jurisdiction exemptions, this loophole could result in thousands of tons of VM organic waste going unrecorded and passing into landfills annually. This outcome would only contribute to the anticipated exacerbation of wildfire risk in the future, making the WMP reporting gap all the more poignant.

In alignment with the CARB 2022 Scoping Plan and state organic matter diversion and methane emission reduction goals, California utility generated VM organic waste disposal and diversion practices should be considered in the WMP. If utilities and their contractors are already complying with state laws, barring rural jurisdictional loopholes, the reporting should be relatively easy. If rural jurisdiction loopholes are exempting large volumes of utility VM organic residues from state regulation, the OEIS should make an effort to close the gap. State emission reduction goals require holistic, multi-sector solutions—selectively turning a blind eye will undermine success. This is especially relevant in connection with the aggressive expansion of vegetation clearances and dead and dying tree removals in the HFTD associated with modern utility wildfire risk management approaches and in response to high tree morality rates. It is prudent for utility directed vegetation management activities to avoid exacerbating climate change by supporting the organic waste diversion and methane emission mitigation efforts of the state.

Integrated Distribution System Planning

Investigate ignition risk associated with peak summer loading and overloading risk.

PG&E identified heightened ignition risk in association with distribution asset overloading. This risk could increase in coming years through the convergence of heat waves, peak summer loading, anticipated increases in customer demand due to electrification trends, and high wildfire risk conditions. Awareness and timely mitigation of heightened ignition risk associated with distribution system overloading lies at the intersection of distribution system planning and system hardening. While the IOUs develop integrated distribution system planning reports via the CPUC HDER proceeding, it is prudent for the WMP to develop a complementary understanding of wildfire risk associated with asset overloading in support of integrated distribution system planning. This is especially relevant given SDG&E's 12+ year hardening plans, during which time grid health and customer demand will continue to evolve within the HFTD. SDG&E should be required to develop an understanding of wildfire risk associated with distribution system operations and overloading conditions. SDG&E should consider whether interim mitigations and mitigation prioritization strategies are needed based on its findings and as part of its 12-year system hardening plan and an integrated distribution system planning process.

Decade long, resource intensive WMPs are showing signs of slowing grid modernization and DER deployment.

D.24-10-030 identifies negative impacts on distribution planning and system improvements due to wildfire mitigation work:

> The Staff Proposal contends this impending load growth requires a more robust and forward-looking DPEP. However, the Staff Proposal asserts that current utility processes and regulatory requirements may hinder the move toward an improved DPEP. In the case of PG&E, other extenuating circumstances, such as prioritizing wildfire hardening, may further exacerbate this hindrance. These external influences have also set the underlying conditions for an increase in customer energization delays, which led to the signing of SB 410 and AB 50 described above.[40]

[40] D.24-10-030, p. 26.

Wildfire mitigation grid hardening plans that consume substantial utility resources over the next decade are at risk of hindering the core purpose of utilities, which is to provide timely electric service. GPI is concerned that SDG&E's wildfire mitigation work to-date and 12-year grid hardening plan is already beginning to impact grid modernization efforts and perhaps the rate of electrification. In the 2026-2028 Base WMP Workshop, SDG&E reports that microgrids and distribution communication reliability improvements were descoped to fund "higher priority initiatives."[41] This is particularly concerning since these DER and distribution modernization improvements should be considered as part of a mitigation package to reduce near- as well as long-term outage risk, and are relevant to a hybrid overhead and underground mitigation portfolio that balances reliability, affordability, and cost. DER, microgrids, and distribution communication reliability investments affect PSPS and PEDS capabilities and risk as well as outages risk from other non-wildfire drivers.

Advancing 12-year grid hardening plans that hinder broad distribution system build out, modernization, and DER solutions to customer needs is a growing concern. Utilities must begin to take an integrated and long-term view of its wildfire mitigation plans, not only in the context of risk buydown, but also the knock-on effects of doubling down on a slow, high-cost mitigation portfolio that appears to ignore the need for integrated solutions to address long-term outage risk.

Conclusions

We respectfully submit these comments on the 2026-2028 WMP of SDG&E. SDG&E was an unwittingly early entry to the utility wildfire ignition world, with a series of destructive utility caused wildfires in 2007. As a result, SDG&E has been a pioneer in searching for ways to harden their transmission and distribution systems, and reducing the risk of igniting utility-caused wildfires. Their vegetation management practices, for example, including their treatment of vegetation management wastes, has set a standard that the two larger California IOUs would do well to emulate. On the other hand, we are concerned that SDG&E has weighed their risk analysis too heavily on the side of undergrounding vs.

[41] 2026-2028 Base Wildfire Mitigation Plan Workshop - Part 3. Time 12:17. https://www.youtube.com/watch?v=OWd_xMkBlx4.

covered conductors, and that that may have the effect of slowing down their grid hardening efforts, as well as causing the ultimate price tag to increase. We recommend that SDG&E put additional effort into modeling the costs and benefits of these two alternatives before committing to a single path of future development. We provide herein a series of critiques and suggestions for SDG&E and the OEIS to improve the SDG&E base 2026-2028 WMP. It is our hope that SDG&E will continue to absorb the lessons learned by all of the IOUs with respect to the strengths and weaknesses in their WMPs.

For the reasons stated above, we urge the OEIS to adopt our recommendations herein.

Dated June 13, 2025.
Respectfully Submitted,

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