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Office of Energy Infrastructure Safety Wildfire Safety Division

COMMENTS OF THE GREEN POWER INSTITUTE ON THE SCE 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 SCE 2026-2028 Wildfire Mitigation Plan*.

Introduction

The GPI performed a review of the Southern California Edison Co. (SCE) 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 these aspects of the WMP. Our comments on other IOU WMPs, identified as applicable to all IOUs and WMPs in general, apply here.

I. Risk Methodology and Assessment (WMP Section 5)

A. Suppression modeling is inconsistent across utility wildfire risk planning models.
B. Issue an ACI for SCE to report on its BCR method in the 2027 WMP Update and provide a guidance that will improve method alignment.
C. SCE's maximum consequence method modification based on Fire Climate Zones is an improvement.
D. Require SCE to complete a third-party review of its risk planning models.

II. Wildfire Mitigation Strategy Development (WMP Section 6)

A. SCEs progress with REFCL pilots and deployment as part of an overhead mitigation package position it to implement adaptive overhead system modifications over time.

III. Wildfire Mitigation Approaches (WMP Sections 8)

A. Ground-Level Distribution System (GLDS) and At Grade Duct Bank (AGDB) pilots.

B. Continue to benchmark with other IOUs on overhead mitigation, inspection, and grid monitoring technologies.

IV. Vegetation Management (Section 9)

A. Improve reporting on VM residue landfill diversion, defensible space practices, and the debris tracking tool.

B. SCE and other IOUs should report on plans to conduct VM work under the Governor's March 2025 Proclamation of a State of Emergency.

C. SCE partnerships should explore fuels management project partnerships in addition to its knowledge-based partnerships.

V. Vegetation Management (Section 11)

A. Support for agency aerial suppression is preferred to aerial suppression fleet ownership.

B. DER programs should be further developed, should have quantitative targets and cost-benefit assessments, and should be included in Section 8 of the WMP.

C. DER programs should phase out fossil fuel generators.

VI. Integrated Distribution System Planning

A. Downstream impacts of WMP grid hardening on IOU distribution grid build out and modernization should be closely monitored.

B. New substations and REFCL.

Comments

Risk Methodology and Assessment (WMP Section 5)

Suppression modeling is inconsistent across utility wildfire risk planning models.

In earlier comments (2022), GPI identified that none of the IOUs had begun to model suppression impacts at the time; therefore all IOUs, not just one, should be issued the same

ACI regarding suppression modeling; and highlighted the uncertainty of inputs and assumptions regarding suppression and the potential error it may introduce to wildfire risk planning models.[e.g.1] We also previously noted that there are a wide variety of big-picture policy considerations relevant to suppression modeling.[2] For example, many factors impacting wildfire risk and suppression are linked to the built environment and human factors, which are subject to high uncertainty. One recent study found that much of the post-wildfire rebuild either did not reduce wildfire risk or even increased risk as re-development took place over many years.[3] In this example, incorrect assumptions about the fire-resistance of post-fire rebuilds could inadvertently exacerbate local risk. Wildfire suppression capacity is also a function of investments, which are subject to change over time.[e.g. 4] GPI is concerned that the fluidity of these and other suppression variables make suppression modeling highly uncertain, especially over the lifespan of utility infrastructure (40+ years).

Suppression modeling was initially addressed by ACI SDGE-22-05, SCE-22-05, and PGE-22-04 (IOU 2022 WMP filings). Decisions issued on the 2023-2025 Base WMPs determined that the IOUs "sufficiently addressed the required progress thus far" and OEIS "will continue to monitor progress."[e.g.5] Skipping ahead to the present 2026-2028 Base WMPs, PG&E has incorporated suppression access based on TDI into its wildfire risk planning consequence model.[6] SDG&E alludes to possible future suppression considerations based on "integrating Moody's RMS into the wildfire CoRE model."[7] SCE identifies suppression as a factor outside of utility control with inherent uncertainty and therefore elects to utilize unsuppressed wildfire simulations in its consequence model and to inform mitigation selection. PG&E and SDG&E's staggered adoption will delay model

[1] Comments of the Green Power Institute on the OEIS Draft Decision on PG&E's 2022 WMP Update, p. 8.
[2] Comments of the Green Power Institute on the OEIS Draft Evaluation of SCE's 2022 WMP Update, p. 5.
[3] Syphard, A. D., Bar Massada, A., Butsic, V., & Keeley, J. E. (2021). Post-wildfire rebuilding and new development in California indicates increasing wildfire exposure. *Landscape and Urban Planning*, https://www-sciencedirect-com.ezproxy.library.unlv.edu/science/article/abs/pii/S0264837721002258.
[4] Ahead of peak fire season, California adds second C-130 airtanker to world's largest aerial firefighting fleet. April 2025. https://www.gov.ca.gov/2025/04/24/ahead-of-peak-fire-season-california-adds-second-c-130-airtanker-to-worlds-largest-aerial-firefighting-fleet/.
[5] Decision on San Diego Gas & Electric Company's 2023-2025 WMP, p. A-10.
[6] PG&E 2026-2028 Based WMP R0, p. 68.
[7] SDG&E 2026-2028 Base WMP R0, p. 79.

comparison by an unknown number of years. In effect, the 2026-2028 WMPs mark a further divergence in applied risk planning model methodology in relation to suppression sub-models.

GPI questions whether it is prudent or equitable to California ratepayers to apply disparate risk model features and methods, such as suppression, for the purpose of long-term grid hardening selection across the IOUs. Suppression models can either increase or decrease localized consequence scores based on a wide range of factors. Decreasing local consequence scores based on suppression would in effect justify lower cost, long-term mitigations in these areas compared to a "baseline" consequence. In contrast, elevated consequence scores based on suppression models could be used to justify higher cost long-term mitigations relative to a "baseline" consequence. Inconsistent suppression modeling in risk planning consequence models between utilities can result in inconsistent grid hardening outcomes and costs for ratepayers across California, in effect shifting each IOU's balance of safety, reliability, and cost.

GPI urges alignment across IOU models. We recommend contracting a third-party to assess the full spectrum of variables that impact wildfire suppression, their relative uncertainty, and how they impact model output and mitigation selection, as well as compare IOU suppression models before they are applied for grid hardening selection purposes. An independent review on wildfire suppression factors, including updated lessons learned from the 2025 LA Fires, would help guide suppression modeling decisions in the WMP towards a unified approach for California ratepayers. As IOU risk planning models continue to diverge with each WMP cycle, it becomes increasingly difficult to find alignment opportunities and to assess whether California ratepayers will bear equitable cost burdens informed by similar safety and reliability risk tolerances.

Issue an ACI for SCE to report on its BCR method in the 2027 WMP Update and provide guidance that will improve method alignment.

Benefit-cost ratio (BCR) method development and application are in the early stages within the WMP. SCE reports that it is not required to implement the BCR approach until after its forthcoming 2026 RAMP filing.[8] It also reports that it transformed its MARS units into a cost-benefit ratio according to a summarized method. However, the method provided in the WMP appears to only show natural unit ranges, weights, and scaling factors for safety, reliability, and financial as well as an example for converting financial risk into a MARS compatible unitless risk score.[9]

GPI recommends issuing SCE an ACI requiring it to report on its BCR method, whether in progress or completed, in its 2027 WMP Update (2026 filing). This transparency will support proactive review and discussion on SCE's method, preferably prior to full implementation. It will also allow all WMP stakeholders, including utilities and the OEIS, to assess methodological differences in the early stages of BCR application—a critical need for subsequent alignment, before disparate methodologies become entrenched for WMP application.

The WMP continues to suffer from a lack of enforceable guidelines as it pertains to model design and mitigation value assessment. Utilities proactively developed their own versions of granular risk planning models in advance of requirement and therefore with the benefit of minimal external guidelines. While admirable from a foresight perspective, the issue from a regulatory standpoint is threefold: (1) Loose risk tolerance standards, design criteria, or guidance results in disparate models that can equate to a variable safety, reliability, and affordability balance for California ratepayers depending on service territory; (2) Proactive method development in advance of agency orders results in utility-guided models that are developed, applied, and ultimately entrenched in utility approaches or forward project plans prior to external review, such that any required modifications have a 1+ year impact lag on utility actions; (3) Wide variability in models developed without design criteria may not have sufficient commonality to support downstream incremental alignment. Independent utility method development in a guideline "vacuum" will consistently result in 3+, and upwards of 6+, model methodologies for the same metric, which will generally be incomparable based on different underlying inputs, model architectures, and outputs.

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[8] SCE 2026-2028 WMP, p. 95.
[9] Ibid.

In the case of the BCR metric, GPI strongly recommends getting ahead of the curve, reviewing the minimum requirements and precedent set in external proceedings and filing requirements (e.g. RAMP), and finding the regulatory space in which to issue guidelines for quantifying and applying a BCR specifically for application in the WMP with the objective of increasing transparency and balancing safety, reliability, and affordability for all ratepayers via common design requirements. For example, including return on equity as part of the mitigation cost to reflect a ratepayer-focused BCR and developing BCR for mitigation packages over their useful lifetime (e.g. 55 years). Early phase BCR method reporting and guidelines will be critical for aligning BCR methods across the IOUs for the purpose of WMP application, before disparate methods are entrenched. One option is to order the IOUs to develop a joint BCR method for WMP applications, which would at least create a common framework that aligns with external proceeding requirements and that provides a basis for method comparison. Precedence for this approach can be found in a variety of CPUC proceedings.

SCE's maximum consequence method modification based on Fire Climate Zones is an improvement.

In a Risk Management Working Group (RMWG) meeting on potential sources of model bias, GPI raised concerns that SCE's maximum consequence model could result in unintended risk distribution biases and mitigation outcomes. SCE previously determined its High Risk Area (HRA) and Severe Risk Area (SRA) risk mitigation tranches in part based on 8-hr Technosylva fire spread simulations that reached 300+ and 10,000+ acre fire footprints, respectively. Fire spread simulations were completed across SCE's territory based on 444 worst weather days and the maximum consequence was used to classify each location as HRA or SRA (or Other HFRA). The original 444 worst weather days were selected from a 20-year data set at the scale of SCE's territory.[10]

GPI's concern was that each of the 444 worst weather days intrinsically have a likelihood of occurrence. For example, the Lahaina fires occurred under conditions considered to have a

[10] SCE 2023-2025 WMP, p. 153.

1-in-2,000-year return interval.[11] As another example, the August 14-15, 2020, extreme heatwave was a 1-in-30-year event.[12] Furthermore, they are likely spatially heterogeneous fire weather and condition layers, meaning conditions are not necessarily equally severe across the entirety of SCE's territory for each fire weather layer. Selecting the maximum simulated fire consequence output from a stack of 444 simulations based on worst weather data "layers" could result in a variable granular likelihood of occurrence "planning standard." The effect is likely exacerbated by selecting worst weather days at the territory level.

For example, both location A and B have a matrix of 444 fire simulation outputs. For location A, the maximum consequence is from simulation #178, while at location B the maximum consequence is simulation #399. However, it is possible that location A maximum consequence is based on 1-in-15-year fire weather conditions that may or may not be a true "maximum consequence" for the 20-year dataset. While location B is based on a 1-in-50-year weather event. This could result in classifying Location A as HRA and B as SRA effectively based on different planning standards that result in different mitigation packages. In this example, if Location A's fire spread outcome matrix had included more severe, lower likelihood fire weather for its location, it may have been classified in the SRA tranche.

The extent and impact of this potential bias in SCE's risk planning model output and resulting risk tranche designations cannot be discerned directly from the risk planning model output. And, determining the spatially heterogeneous return interval for each for the 444 weather layers would be an unreasonable task with minimal return on investment, since we suspect it would only identify the extent of the bias without necessarily resolving it. Within its existing model framework SCE adjusted for the bias in a couple ways, including: (1) more granular selection of fire weather layers to ensure local maximums are captured; and

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[11] SCE 2025 WMP Update, p. 37.

[12] California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), & California Energy Commission (CEC). (2021, January 13). *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*. p. 4. Retrieved from https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

(2) a longer historical fire weather dataset that includes more severe, lower frequency events.

SCE's modified method offers a correction which identifies that the potential bias would be exacerbated by selecting its worst weather days based on territory-wide weather layers, versus identifying local maximums based on more granular zones, such as its 13 Fire Climate Zones (FCZs). SCE's modified approach develops a Fire Behavior Matrix (FBM) for each of 13 FCZs. Each FBM is divided into 16 Fire Behavior Observations (FBO) regimes based on weather and dryness. All weather days from a 40-year dataset are classified into the FBO bins at the resolution of the FCZ. Worst weather days are selected for fire spread simulation (Technosylva) for each FCZ based on a percentage of days (1-100%) in each of the fire-risk FBO bins. This approach increased the total number of worst fire-weather condition days selected for fire spread simulations from 444 to 1,713 worst weather days.[13]

GPI believes that the selection of worst weather days based on more granular FCZ, and classification of all fire weather data into FCZ specific FBM prior to selecting worst weather days is an improvement that mitigates potential unintended bias in SCE's previous maximum consequence method. This method is more likely to identify local maximums for each FCZ. Overall, we believe that SCE's planning model update likely improved the output.

SCE also migrated its IWMS from a 20-year dataset to a 40-year historical-weather data set. This change is likely to capture more severe and less frequent fire-weather conditions in SCE's risk planning model output. Indeed, SCE's 2023-2025 WMP reports that the 444 weather scenarios captured a 1 in 50-year event frequency.[14] Its 2026-2028 WMP IWMS includes the original 41 fire weather scenarios use in the HFTD maps that reflect a 50-year return interval.[15] The expanded historical data set also includes "credible worst case" event

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[13] SCE 2026-2028 WMP, p. 85.
[14] SCE 2023-2025 WMP, p. 157.
[15] SCE 2026-2028 WMP, p. 112.

conditions (exceedance of 1 percent over the 3 year WMP cycle, 300-year return interval).[16] Since SCE employs maximum consequence, the extended historic weather dataset may elevate wildfire risk model consequences across SCE's territory. We also note that the downstream impacts of historical weather year dataset durations (e.g. 40-year versus 20-year datasets) on model output cannot necessarily be directly compared between a maximum consequence model and a probabilistic model, since they consider the data input differently.

A couple of ways the impacts of these updates could be assessed include: (1) a comparison of the fire weather data layer that resulted in the maximum consequence for each fire simulation node before and after the model update; and (2) a comparison of risk tranche classification before and after the model update. GPI had insufficient time to conduct these assessments. In general, it would be prudent to require a third-party review of SCEs risk planning model.

SCE's maximum consequence model may still impart a patchwork of fire weather condition frequencies across its service territory in its planning model. The 3-tranche system for mitigation selection may smooth out some of the potential downstream impacts on mitigation selection. For example, a 1-in-50-year versus 1-in-300-year event fire-spread simulation at the same location that both result in burn footprints of 10,000+ acres in the first 8 h, would both classify the location in SCE's SRA tranche. Meaning the eligible/preferred mitigations would not change for this location regardless of which fire condition event layer was used within the maximum consequence model. In general, model design and application via output thresholds for mitigation selection (e.g. risk tranche classification) becomes a question of "tipping" points. Additional model assessments would be required to explore the potential downstream impacts on mitigation selection.

SCE will complete most of its major grid hardening work by the end of the current WMP cycle. Its 2023-2025 WMP included 2,850 miles of covered conductor and 75 miles of undergrounding.[17] The 2026-2028 WMP targets 440 miles of covered conductor and 260

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[16] Ibid, p. 113.
[17] SCE 2023-2025 WMP, p. 238.

miles of undergrounding, which is somewhat consistent with its prior WMP cycle and SCE's more balanced mitigation approach. This suggests some possible changes to their grid hardening plan on account of model changes. Importantly, SCE's mitigation options include a robust CC++/REFCL overhead distribution system mitigation package that allows SCE to incrementally bolster the effectiveness of its existing overhead hardened lines—meaning SCE is positioned to adapt its system in response to changes in granular risk profiles, whether on account of risk model updates or other drivers such as changing environmental conditions (e.g. climate change).

Require SCE to complete a third-party review of its risk planning models.

SCE states that it "does not currently conduct external third-party independent reviews of data collected and risk models…," instead completing an internal process.[18] It has retained third party contractors to review its RSE method and consult on risk model documentation templates. GPI recommends issuing SCE an ACI requiring it to contract a third party to review its risk planning model design. This should be a consistent requirement for all IOUs. We further suggest that SCE retain Energy + Environmental Economics (E3) to complete the planning model review. E3 is a trusted third party that has consulted for the CPUC and conducted the recent independent review of PG&E's WMP risk planning model.[19]

Bringing all independent reviews of IOU risk planning models under the same consultant will set up the ability to efficiently fulfill a critical need for utility risk planning model cross comparison. The RMWG focuses on individual components of utility risk models and has not necessarily considered holistic model design. For example, a RMWG meeting presented SDG&E's natural unit cost conversion metrics such as VSL, cost per destroyed building, and cost per customer outage minute. However, when reviewing SDG&E's model they further applied risk-averse scaling that was not presented at the RMWG meeting, and that effectively alters the natural unit cost conversion according to a sliding scale. Meaning the RMWG content was one part of the "whole picture" that did not capture downstream

[18] SCE 2026-2028 WMP, p. 138.
[19] E3. (2025, May 13). *E3 Selected to Lead the Next Phase of CPUC IRP Support*. Retrieved from https://www.ethree.com/cpuc-irp-award/.

modifications. At this phase, the WMP development process seems no closer to materially aligning utility risk planning models. A third-party independent review of each IOU risk planning model as a whole, as well as a cross-utility comparison, is one option to advance the effort towards improved model and output alignment.

SCE will complete the bulk of its grid hardening in the current WMP cycle. However, it is still prudent to progress towards improved risk planning model alignment. We anticipate that all IOUs, including SCE, will continue to serve an evolving customer base on top of a landscape with evolving wildfire risk. This includes factors such as geographic distribution (e.g. WUI expansion, urbanization), vulnerable population shifts, and demand profile. Granular wildfire and outage risk may change over time due to factors such as future forest fire impacts and climate change. In the coming decades, utility risk planning models will continue to guide mitigation adaptations for existing distribution and transmission infrastructure (e.g. recently upgraded) as well as grid design where new infrastructure is needed, all in response to changing customer demand and wildfire risk.

Wildfire Mitigation Strategy Development (WMP Section 6)

SCE's progress with REFCL pilots and deployment as part of an overhead mitigation package position it to implement adaptive overhead system modifications over time.

SCE's REFCL/CC++ overhead mitigation package, risk reduction efficacy is identified as on par with undergrounding.[20] SCE is the only California utility to successfully evaluate a variety of REFCL technologies via multiple pilots and to integrate REFCL into its overhead risk mitigation package. SCE's REFCL documentation from the 2023-2025 WMP reports the orders of magnitude improved sensitivity and energy release reduction of REFCL versus Fast Curve Enabled protection devices.[21] SCE's pilot work has identified supply chain bottlenecks as well as technical challenges. The 2023-2025 REFCL report mapped out efforts to develop a North American supply chain and continue pilots towards addressing implementation challenges. SCE's 2026-2028 WMP sets a target of 5 Ground Fault

[20] SCE 2026-2028 WMP, p. 179.
[21] REFCL Projects at Southern California Edison, p. 4.

Neutralizer and 8 Grounding Conversion REFCL installations over the WMP cycle. It also reports on these mitigations in the "Emerging Grid Hardening Technology Installations and Pilots" section of the WMP.[22] We understand this to mean that while SCE has adopted REFCL technologies as part of a standard mitigation package, it continues to address the associated challenges and supply chain issues.

GPI appreciates this ongoing development process and recommends that SCE provide an updated report on its progress addressing the challenges laid out in the "Rapid Earth Fault Current Limiter (REFCL) Projects at Southern California Edison" R0 report, which is dated December 2022, and was submitted with both the 2023-2025 WMP and current 2026-2028 WMP filings. Since the report was completed, 3.5 years have lapsed. An update on pilot progress, persistent REFCL deployment challenges, and regional supply is relevant to understanding the future of REFCL in wildfire mitigation at SCE and other utilities.

SCE's progress with REFCL technology pilots and deployment as part of an overhead mitigation package has future grid adaptation benefits. Distribution systems are modified over time and are also built upon systems that change over time. Meaningful system change can occur over the useful life of distribution assets (e.g. 40+ years) and will likely include factors such as increasing wildfire risk due to climate change, vulnerable customer distributions, and changes in the WUI footprint. This calls for risk mitigation tools that support incremental system adaptations in response to changing conditions. SCE's progress on REFCL today will establish a pathway to evolve its overhead system over time in response to a changing service territory. It will be critical for all IOUs to develop overhead mitigation portfolios that support system adaptations to changing conditions. Additional pressure should be levied on SDG&E and PG&E to benchmark with SCE and more thoroughly assess REFCL deployment in their service territories for the purposes of present-day risk reduction, future risk mitigation and overhead grid adaptation, and new infrastructure buildout (e.g. proactive integration at new substations that may serve high wildfire risk circuits).

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[22] SCE 2026-2028 WMP, pg. 246.

Wildfire Mitigation Approaches (WMP Sections 8)

Ground-Level Distribution System (GLDS) and At Grade Duct Bank (AGDB) pilots.

SCE's WMP includes a Ground-Level Distribution System (GLDS) and At Grade Duct Bank (AGDB) pilot that offers an alternative to traditional undergrounding. In addition to wildfire risk reduction, SCE's pilot will assess the range of potential benefits such as cost savings, less invasive construction, deployment in a wider range of terrain, and reliability value. SCE's Ground-Level Distribution System (GLDS) and At Grade Duct Bank (AGDB) undergrounding pilot is commendable. We are hopeful that these surface-level designs will offer a promising and cost-effective alternative to traditional undergrounding and overhead systems that addresses challenges such as high-cost installation and repairs as well as residual risk exposure, respectively.

We commend SCE for reporting on its GLDS and AGDB pilot in its WMP and advocate for additional transparency. We recommend that SCE provide a more detailed plan for its GLDS and AGDB pilot, including pilot locations, scope of work (e.g. miles deployed), timeline, and how the pilot is right sized to provide meaning full results in the near-term (e.g. 1-3 years). We also recommend issuing an ACI that requires SCE to provide annual updates on its GLDS and AGDB pilot, including progress to date, challenges encountered, lessons learned, etc. This information should be readily available from internal pilot documentation and tracking.

GLDS was mentioned briefly in the March 2025 Joint IOU Grid Hardening Working Group Report.[23] The report mentions a joint utility assessment of GLDS as well as an SDG&E specific pilot. SCE's 2026-2028 WMP mentions benchmarking with PG&E's pilot. Yet, PG&E's 2026-2028 WMP does not mention a GLDS pilot. SDG&E's WMP only mentions GLDS in the attached Joint IOU Grid Hardening Working Group Report. AGDB is not mentioned in the report nor in PG&E or SDG&E's 2026-2028 WMP. The 2026-2028 Base WMP is a 3-year plan that is specifically required to include wildfire risk mitigation pilots

[23] Joint IOU Grid Hardening Working Group Report: Update for 2026-2028 Wildfire Mitigation Plan, pgs. 18-19.

on new and emerging grid hardening technology. GPI recommends ordering PG&E and SDG&E to revise their WMPs to include details on their GLDS investigations and pilots to date, including already deployed GLDS assets and pilot plans for the 2026-2028 WMP, (i.e. the same content recommended for SCE additional reporting above).

Continue to benchmark with other IOUs on overhead mitigation, inspection, and grid monitoring technologies.

GPI encourages SCE to continue to benchmark with other IOUs on overhead grid hardening, inspection and grid monitoring techniques that will continue to advance its already robust overhead mitigation packages. SCE appears to implement perhaps the most robust overhead distribution system mitigation package and has done so quickly across its service territory to rapidly reduce wildfire risk. We encourage SCE to continue exchanging in-house knowledge of overhead system design and pilots with the other IOUs and SMJUs. For example, PG&E's recent expanded use of Gridscope for real-time grid monitoring, which helps locate faults. Gridscope may also prove beneficial for SCE's overhead system and fault finding on REFCL enabled circuits.

We anticipate that ongoing grid hardening, inspection, and monitoring innovations will continue to improve overhead and underground system wildfire and outage risk mitigations. Complementary overhead system technologies will be especially relevant for incrementally bolstering the effectiveness of existing overhead assets with long useful lifetimes, as utility service territories change over time.

Vegetation Management (Section 9)

Improve reporting on VM residue landfill diversion, defensible space practices, and the debris tracking tool.

SCE sets qualitative target VM-11 to "review and identify potential updates to contract terms for debris management, with implementation contingent on contract execution timing."[24] SCE's wood and slash management includes reducing VM slash through required

[24] SCE 2026-2028 WMP, p. 330.

contractor chipping, raking, and hauling to leave VM sites in their original condition, unless otherwise requested by the landowner.[25] It also mentions VM material disposal or recycling, but does not provide a metric of the proportion of VM residues diverted from landfills. In 2024, SCE piloted a debris tracking tool for coordination with contractors. SCE's VM slash removal process is possibly more progressive than other utilities. Though where contractors offload the resulting materials and whether they are subject to state organic-matter landfill diversion requirements remains unknown. WMP improvements should include reporting on the amount of VM residues diverted from landfills in accordance with state goals and any specific practices to ensure customer defensible space is maintained as it pertains to VM wood as well as slash. SCE should also be required to report on the design, purpose, and outcomes of its existing debris tracking tool as well as outcomes of its VM-11 target in its 2027 WMP Update.

California has a long history of developing innovative solutions to managing woody biomass accumulations from a wide range of sources including agricultural prunings, household organic waste, and dead and dying trees. Early efforts include the 2015 Governor proclamation on Tree Mortality which included provisions for the use of the resulting wood products such as in landscaping woodchips, forest bioenergy facilities (BioMAT), and wood product markets.[26] In the intervening decade, additional mandates were enacted to divert woody biomass from landfills to avoid methane emissions, as identified by the CARB 2022 Scoping Plan. Development efforts for a California wood products market also persist.[27] It is past time for WMPs to transparently align with California state goals to divert woody biomass from landfills and into other value-add end uses that reduce methane emissions associated with landfill disposal. We urge the IOUs to improve transparency into their current VM residue landfill diversion efforts, investigate contractor practices, and develop and report plans to improve VM residue diversion from landfills. The OEIS should drive this progress and alignment with California state goals and statute through updated reporting

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[25] Ibid, p. 346-347.
[26] Governor's Proclamation Tree Mortality 2015-05. https://www.caloes.ca.gov/wp-content/uploads/Recovery/Documents/Governors-Proclamation-Tree-Mortality-2015-05.pdf.
[27] California Business and Economic Development. Wood Product and Biomass https://business.ca.gov/industries/wood-product-and-biomass/.

requirements, including those previously recommended in GPI comments throughout the modern WMP development process.

SCE and other IOUs should report on plans to conduct VM work under the Governor's March 2025 Proclamation of a State of Emergency.

In March 2025 Governor Newsom issued a Proclamation of a State of Emergency regarding fuels management and a suspension of state EPA and CNRA statutes, rules, regulations, and requirements for "critical fuels reduction projects" that include the removal of hazardous, dead, and/or dying trees, as well as other fuels management projects. This proclamation not only applies to work by agencies, but also individuals and entities, who must issue a request to the appropriate agency and receive a formal project determination. In the 2027 WMP Update, SCE and all utilities subject to WMP filings should report on whether the Proclamation provisions offer a pathway to complete VM work that is hindered by permitting, including backlogged VM work or whether it offers new opportunities for dead and dying tree mitigation along its infrastructure.[28] If so, utilities should report on the projects they intend to propose and implement under the Proclamation. Utilities should also report whether they will form partnerships with agencies completing additional fuels management work under the Proclamation (e.g. new fire breaks, management of existing fire breaks).

SCE partnerships should explore fuels management project partnerships in addition to its knowledge-based partnerships.

PG&E and SDG&E report partnerships and funding that advance fuel treatment work within their territories, in proximity to utility infrastructure and the communities they serve. SCE's vegetation management partnerships largely focus on inspections, arborist training program development, information exchange, and applied research as it relates to utility vegetation management work. Engagement in these spheres is commendable. However, SCE's efforts are largely upstream of applied fuels management that proactively support firefighting

[28] SCE 2026-2028 WMP, p. 367.

efforts and mitigate wildfire consequence in the event of an electrical asset ignited wildfire.[29]

We recognize that current best practices for fuel treatments depend on ecoregion. Fuel breaks and roadway ignition reduction projects are identified as fuel treatment approaches that support wildfire risk mitigation in Southern California, and are active areas of work for USFS, CAL FIRE, and other California agencies and non-profits.[e.g.30] Strategic partnerships with these California agencies to support fuel treatments can simultaneously mitigate risk and advance statewide understanding of fuel treatment effectiveness. For example, CAL FIRE's recent fuels treatment effectiveness dashboard and reports link fuel treatment work to wildfire consequence mitigation outcomes.[e.g.31,32]

Within the WMP framework, fuel treatments offer interim and ongoing wildfire risk mitigation value if properly maintained. Utilities and ratepayers are benefiting from these fuel treatment activities through utility asset ignition consequence mitigation as well as received risk mitigation. Utility directed funding via partnerships can supplement other external funding sources to both expand and sustain fuel treatments within proximity to utility assets.

In general, utility directed fuel treatment funding may also benefit from improved transparency and coordination with system hardening work plans and risk model outputs. For example, allocating funding for partner-directed fuel treatments planned in the vicinity of overhead hardened lines and/or corresponding to asset risk based on utility risk model outputs. A holistic WMP and risk directed approach could help to ensure that resulting ratepayer investments are aligned with utility risk. Utility directed fuel treatment funding

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[29] Ibid, p. 350-351.

[30] **California Wildfire & Forest Resilience Task Force.** (2025, February 5). *Managing Wildfire Risk in Southern California's Chaparral Landscapes*. https://wildfiretaskforce.org/managing-wildfire-in-southern-californias-chaparral-landscapes/.

[31] **CAL FIRE** (n.d.). *Fuels Treatment Effectiveness Reporting Dashboard: Treatment Reporting Overview*. https://experience.arcgis.com/experience/91ab6b7f0b414d0ea06bf269a4632e15/page/Treatment-Reporting-Overview.

[32] **CAL FIRE** (n.d.). *Fuels Reduction*. https://www.fire.ca.gov/what-we-do/natural-resource-management/fuels-reduction.

via partnerships and a WMP-informed approach could also complement and even free-up non-utility funds for allocation to fuel treatment projects elsewhere in the state.

To date, utility funding for fuel treatment is dwarfed by other utility risk mitigation investments including grid hardening and maintenance, which largely focuses on mitigating probability of ignition. We are not recommending a fundamental shift in utilities' high level mitigation strategy. However, given that grid hardening plans extend out into the mid- (3-6 year) and long-term planning horizons (7-10 year) and overhead hardened systems will remain a staple in HFTD distribution system design for the foreseeable future, it is prudent to consider if and how utilities are investing in and supporting wildfire consequence mitigations, including fuel treatments. These considerations should include (1) IOU benchmarking for current practices in wildfire consequence mitigation in each territory (e.g. suppression resource investments) and fuel treatment specifically, (2) current funding allocations, and (3) optimizing those funding allocations to benefit ratepayers, complement other funding sources, and maximize state resources. SCE specifically, should assess whether utility directed funding for partner-managed fuel treatments can simultaneously advance wildfire risk mitigation and upstream applied research in support of improved fuel treatment strategies that reduce risk and serve ratepayers.

Emergency Preparedness, Collaboration, and Community Outreach (Section 11)

Support for agency aerial suppression is preferred to aerial suppression fleet ownership.

SCE reports on its ongoing partnership with local firefighting agencies in support of aerial firefighting resources. SCEs investments in Los Angeles, Ventura, and Orange County fire agency aerial fire suppression resources includes a formal MOU that guides funding for fixed leases and helicopter stand-by time costs. Other aerial suppression costs were borne by the respective fire agencies, including during firefighting. This approach supports aerial firefighting capacity and sustainability, ensuring these resources are available to respond to any wildfire, including those ignited by utility infrastructure. This investment approach appears to mitigate the potential for conflict of interest (e.g. sway dispatch decision making, cover costs to fight non-utility ignited fires, etc.). SCE's approach offers a degree of neutrality, such that local firefighting agencies maintain full jurisdiction and control over factors such as suppression response decision making, resource allocation, and prioritization based on event conditions and available resources, not ignition source.

SCE's approach varies significantly from SDG&E's Aviation Fire Fighting Program which includes ownership of two Sikorsky UH-60 Blackhawk helitankers.[33] These assets and the ops required to manage them presumably include many other ongoing operating requirements and costs such as hanger space, insurances, regular maintenance, FAA certified pilot and crew payroll, pilot certification maintenance requirements (e.g. flight hours), flight operations support personnel and resources, and dispatch from/ coordination with regional firefighting agencies to be eligible to enter wildfire areas with Temporary Flight Restrictions (TFR NOTAMs) in order to provide suppression support.[e.g. 34] SDG&E cites an estimated 4 percent utility wildfire risk reduction from this program and suggests that their Sikorskys stopgap instances when non-utility owned aerial firefighting resources are diverted to out of territory events. SDG&E's approach divides wildfire suppression investments between its own aerial fire firefighting outfit and that of local agencies, versus of bolstering local agency capacity. This investment may also result in redundant costs for aerial firefighting operation centers at SDG&E and fire agencies and may add coordination complexity for fire agencies. It also raises the question whether available aerial firefighting resources should be withheld from responding to non-utility ignited fires or those with unknown ignition sources; whether this may negatively impact optimal suppression resource allocation in the interest of utility wildfire risk mitigation; and if dispatch of SDG&E helitanker investments could be influenced by conflict of interest. Direct engagement in aerial firefighting is outside the jurisdiction of the utilities and may constitute investment inefficiencies and/or operational inefficiencies for agencies tasked with implementing wildfire suppression. The primary role of a utility is to deliver safe, reliable, and affordable electricity, which includes preventing its assets from starting wildfire, and ignitions from become wildfires, not fighting wildfires. Utility owned aerial firefighting operations should be scrutinized for utility overreach.

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[33] SDGE p. 201.
[34] See https://www.faa.gov/air_traffic/publications/atpubs/aip_html/part2_enr_section_5.1.html.

GPI supports SCE's approach to post ignition and wildfire control, which is to bolster the capacity and sustainability of local firefighting agencies; and to trust these agencies to make informed decisions that optimize resource allocation as needed, regardless of the ignition source. Consolidating investments into agencies tasked with wildfire suppression should offer operational and cost efficiencies that broadly benefit Californians as well as the utilities. Utility investment in local firefighting agencies is prudent, as agency capacity and sustainability will determine the ability to suppress utility ignited wildfires as well as asset received risk from all wildfires. MOUs offer partnership transparency and mitigate potential conflicts of interest. GPI recommends scrutinizing IOU investments in firefighting resources and providing guidelines that will align utility approaches.

DER programs should be further developed, should have quantitative targets and cost-benefit assessments, and should be included in Section 8 of the WMP.

SCE correctly identifies their PEDS and PSPS programs as complementary versus interim mitigations. This acknowledges that outages due to PSPS and PEDS will continue to impact its customers as intermittent wildfire risk mitigation controls that take effect during high-risk events. The issue is not simply whether PSPS and PEDS outages occur. As utilities have identified, the impact comes down to the frequency, scale, and duration of the outages as well as the outage ride-through services provided to customers.

Grid hardening, sectionalizing, remote grids, grid monitoring, and situational awareness can reduce the frequency, scale, and duration of outage program events. However, when an outage event does occur, backup energy is the most effective way to address the full spectrum of consequences and meet customer needs.

Consider that mitigating the consequence of a wildfire after an ignition via suppression, falls under the jurisdiction of firefighting agencies. Similarly, mitigating the consequences of an outage by supplying backup energy to customers falls under the jurisdiction of electric utilities – supplying energy to customers is the core function of the electric utility and addressing reliably is a foundational criterion of this service. Energy utilities should consider the patchwork of in-event services that address basic physiological needs – such as air, water, food, shelter, and sleep (Maslow) – as a last-resort safety net. These reactive measures, which compensate for the loss of energy, should be the stopgap if best efforts to keep customers energized comes up short. Consequently, outage program mitigations should first minimize the frequency, scale, and scope of energy outages; second, invoke Distributed Energy Resource (DER) to sustain access to electricity; and third, offer stopgap physiological services to address the impacts of unabated energy loss. Yet, the utilities' ability to maintain their core service by sustaining customer power in the event of an outage and the role of DER is an underdeveloped aspect in the WMP.

Once the footprint, frequency, and duration of outage events has been minimized, repowering impacted customers with DER is the next phase of outage consequence mitigation. DER have a wide range of attributes and applications such as zero-emission versus fossil fueled, stand-alone versus hybrid resources, size (i.e. capacity and energy), portable/temporary/permanent, behind-the-meter (BTM) versus in-front-of-meter (IFOM) interconnections, and plug-in/critical circuit/whole house configurations. Some examples within the WMP context include multi-customer microgrids; hybrid solar plus battery BTM installations;[35] stand-alone batteries charged from the grid and connected to critical circuits to extend backup power duration; and portable batteries that provide power to individual devices and can be recharged at event support facilities or exchanged for fully charged replacements. Other active and related areas of DER innovation include vehicle-grid integration and virtual power plants made possible by coordinating customer sited DER.[36,37] For example, California's Demand Side Grid Support program now includes over 500 MW of capacity from 250,000+ enrolled customers to serve as a coordinated strategic reliability reserve during extreme weather events (i.e. Virtual Power Plant, or VPP).[38] In a WMP

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[35] Standard rooftop solar installations are designed to withstand 90-140 mph winds.

[36] Utility Drive (2022, April 1). *California approves $11.7M vehicle-to-grid pilots in PG&E footprint*. Utility Dive. Retrieved from https://www.utilitydive.com/news/california-approves-117m-vehicle-to-grid-pilots-in-pge-footprint/621393/.

[37] California Energy Commission. (2024, October 15). *California's Demand Side Grid Support Program Grows to 500 Megawatts of Capacity*. Retrieved from https://www.energy.ca.gov/news/2024-10/californias-demand-side-grid-support-program-grows-500-megawatts-capacity.

[38] California Energy Commission. (2024, October 15). *California's Demand Side Grid Support Program Grows to 500 Megawatts of Capacity*. Retrieved from https://www.energy.ca.gov/news/2024-10/californias-demand-side-grid-support-program-grows-500-megawatts-capacity.

context, consider the possibility of repowering customers downstream of a fault or PSPS event by activating a VPP.

It is well known that at least a portion of DER total net benefits are a function of their location. Multiple CPUC proceedings have resulted in tools for assessing DER locational value. In the now closed Distributed Resources Proceeding, utilities developed a Locational Net Benefits Analysis to assess the net benefit of DER solutions capable of deferring traditional wire upgrades required to meet distribution system grid needs.[39] The DER Avoided Cost Calculator (ACC) originated from CPUC proceeding R.04-04-025 and has been developed over the years, with the most recent modifications in April 2025. The ACC quantifies the costs avoided by DER such as energy efficiency and demand response products.

Similarly, the net benefits of DER deployed to mitigate WMP outage program consequence and the optimal DER solutions will depend on multiple factors such as customer type (e.g. critical facilities, AFN) and granular outage risk (frequency, duration, scope). The IOUs, including SCE, have the foundational elements necessary to conduct this analysis such as historic weather datasets, granular outage risk models, customer account and spatial distribution datasets, datasets on at least a portion of existing DER, and data on customers that have already opted into DER programs. Utility data can be combined to quantify residual outage program risk and subsequently identify where and what types of DER will be most cost-effective in addressing customer needs as well as the necessary scale of DER programs to substantially mitigate outage event consequences. The IOUs have yet to connect all the dots in the WMP and apply the findings to DER program design.

SCE has rapidly reduced its wildfire risk through widespread deployment of overhead hardened distribution system mitigation packages and targeted undergrounding. However, its DER deployment programs are relatively underdeveloped and perhaps the least developed of the three IOUs. SCE's distributed energy resource deployment programs are

[39] D.17-09-026.

summarized in Section 11.5, "Customer support in wildfire and PSPS emergencies." DER programs planned for the 2026-2028 WMP cycle include:

- Portable Power Station and Generator Rebate Program (PSPS-3)[40]
- Disability Disaster and Access Resources Program which support customer development of backup power plans and offers in-event battery backup[41]
- In-event battery loan pilot[42]
- Customer sider generator, which offers in-event, temporary portable generators[43]
- Critical Care Battery Backup program (free portable backup batteries)[44]
- Remote Grid Feasibility Study (designed to eliminate PSPS risk, not address in-event power loss)[45]

SCE's programs are focused on portable and temporary energy resources. These programs lack any quantitative targets or impact assessments. SCE's in-event temporary backup power programs require direct customer engagement every time a PSPS or PEDS outage occurs, suggesting inefficiencies for both SCE and the customer. It's not clear whether these programs are the most efficient or effective way to serve SCE customers impacted by PSPS and PEDS outages. There is a complete lack of permanent DER offerings either at the residential customer scale in the form of permanent battery installations (e.g. whole-house power, critical circuit power) or at the scale of critical facilities and communities such as larger permanent zero-emission backup power supplies and microgrids. SCE's WMP also does not mention existing DER deployment programs that mitigate PSPS and PEDS consequences, such as the Self Generation Incentive Program (SGIP).

SCE should advance its outage event backup power programs and the range of solutions it offers customers. These programs should include quantitative targets for a variety of DER solutions informed by customer needs and outage program risk (i.e. location, direct and indirect benefits, event durations, frequency). Program advancements should consider how

[40] SCE 2026-2028 WMP, pp. 470-47.
[41] Ibid.
[42] Ibid**.**
[43] Ibid.
[44] SCE 2026-2028 WMP, p. 210.
[45] SCE 2026-2028 WMP, p. 263.

to improve backup power program efficiency such as reducing the number of temporary backup power deliveries required across its service territory in response to PSPS and PEDS outages. Customer needs caused by power outages can be addressed by alternative power supplies. Backup power program design should consider how to reduce the need for last-resort programs that stopgap customer baseline needs (e.g. food, water, fuel, accommodations, cooling/heating etc.). This same framework should guide backup power program development for all IOUs.

Backup power services during WMP outage events are only one portion of the total net benefit of applicable DER deployed within an outage footprint, whether sourced via the WMP, other programs, or customer choice adoption. DERs are increasingly recognized as versatile assets capable of delivering stacked value across multiple grid and customer use cases. Additional services can include backup power during any outage event regardless of risk driver, regional and system level benefits via programs such as Demand Side Grid Support, and during normal operations as a load modifier or energy resource that avoids transmission infrastructure and utility scale generator buildout. Utilities and regulatory agencies have only just begun to scratch the surface of DER value and their capabilities to provide grid services during normal and abnormal grid operation at the local, regional, and system scales. WMP outage programs, outage program-consequence mitigation, and associated DER value is one aspect of a DER value stack and DER deployment driver that falls under the scope of the WMP. Work completed in the WMP can and should be integrated into other proceedings and programs to inform a DER total value stack.

Additional content on DER relevant to all utilities was included in our comments on PG&E and SDG&E's 2026-2028 WMP.

DER programs should phase out fossil fuel generators.

SCE backup power programs offer portable generator rebates and in-event temporary generators.[46] Portable generators fall under California statute that sets higher emissions

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[46] SCE 2026-2028 WMP, p. 470.

standards for off-road motors beginning in 2024 and a complete phase out of new gas-powered generators by 2028, the final year of the WMP cycle. These restrictions were only briefly relaxed through June 30, 2025, on account of demand caused by the 2025 Southern California wildfires.[47] SCE should modify its backup power programs to phase out the deployment of gas-powered generators in accordance with state targets.

Integrated Distribution System Planning

We strongly encourage the IOUs to future proof distribution system design through integrated distribution system planning. D.24-10-030 states:

> While the Commission acknowledges that Utilities are either planning or already conducting integrated planning, transparency is one of the objectives here and neither stakeholders nor the Commission have a window into the processes Utilities undertake to integrate planning.[48]

The IOUs' 2026-2028 WMPs offered little in the way of improved OEIS, CPUC, or stakeholder transparency regarding utility integrated distribution system planning. GPI looks forward to the forthcoming Q3 2025 workshops (2) and Q4 2025 Tier 3 AL intended to increase transparency into utility integrated distribution system planning including as it pertains to wildfire grid hardening programs.[49]

Downstream impacts of WMP grid hardening on IOU distribution grid build out and modernization should be closely monitored.

GPI has not yet identified evidence of downstream slowing of distribution system buildout and modernization due to SCE's WMP grid hardening approach. Information on this subject is relatively sparse but should remain a point of interest in the WMP. The utilities fulfill a role as sole distribution grid developers – delays in this area can result in customer

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[47] California Air Resources Board. (2025, January 10). *California Air Resources Board eases requirements on portable generators to meet increased demand during wildfires*. Retrieved from https://ww2.arb.ca.gov/news/california-air-resources-board-eases-requirements-portable-generators-meet-increased-demand.
[48] D.24-10-030, p. 86.
[49] Ibid.

interconnection delays. Grid modernization includes upgrading to Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS), which create value through utility applications such as WMP programs (e.g. granular fault location, PSPS and PEDS events, DER applications). Staying on track with distribution grid build out and modernization is critical for many reasons including creating the infrastructure necessary for successful statewide electrification and emission goals as well as the integration of DER (including EVs) and materializing DER value.

New substations and REFCL.

New busbars are sometimes proposed via the IRP busbar mapping process driven by a need for upstream utility-scale resource interconnection to the grid. Any new substations that directly connect to distribution systems and that are in the proximity of the HFTD may benefit from an integrated system design approach that includes RECFL at the time of the build or supports more seamless addition of REFCL in the future. We encourage SCE to report on any related efforts in the 2027 WMP Update.

Conclusions

We respectfully submit these comments on the 2026-2028 WMP of SCE. We urge the OEIS to adopt our recommendations herein.

Dated June 27, 2025.
Respectfully Submitted,

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