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Wildfire Safety Division
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COMMENTS OF THE GREEN POWER INSTITUTE ON THE
2021 WILDFIRE MITIGATION PLAN UPDATES

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The Green Power Institute, the renewable energy program of the Pacific Institute for Studies in Development, Environment, and Security (GPI), provides these *Comments of the Green Power Institute on the WSD 2021 Guidance on Engagement of Independent Evaluators*.

GPI's comments focus on the content within the IOU 2021 WMP Updates. Due to resource limitations we are unable to complete a comprehensive review of the February 26, 2021, or Quarter 4 reports. Our primary concerns include PG&Es granular risk modeling methodologies, ability to project risk reduction outcomes, delays in risk mitigation due to faulty modeling in 2019-2020, and trends in the utilities' inspection findings. Additional concerns include vegetation management locational prioritization, residue removal and end-use, and PSPS mitigations and risk assessment.

We address the following topics in these comments:

- The WMP reporting process and cycle would benefit from additional refinements.
- PG&E has limited ability to quantify wildfire risk mitigation capabilities and/or mitigate wildfire risk.
- Risk Modeling and the risk of not getting it "right": Wildfire and ignition risk models require comprehensive and transparent vetting.
- Utility mid- and long-term planning statements are still dominated by generalized visions and broad "goals" versus including more concrete objectives that guide planning decisions.
- Utilities state that third party vetting occurred but often do not provide who the third parties are or summarize the results.
- The quality of information provided in Section 4.4.2 "Research Findings" varies widely.
- Table 1 data assessment: PG&E likely has numerous undiscovered Level 1, 2 and 3 "findings."
- PG&E Field Safety Assessments.

- Vegetation Management: PG&E's Tree Assessment Tool (TAT) and SCE's Tree Risk Calculator appear to be replacing certified arborists in VM and EVM decision making.
- Vegetation Management: VM generated fuel load management and residue end-uses.
- Vegetation Management: Fuels management, herbicides, fire retardant and IVM effectiveness.
- Vegetation Management: Locational prioritization methodology and modeling.
- PG&E should explain why the cost of Transmission substation defensible space work is increasing.
- PSPS: All electric corporations should develop PSPS risk models at a circuit-level granularity or better to inform initiative selection and prioritization.
- PSPS: Post PSPS inspection findings should inform the evaluation of otherwise masked risk events to guide PSPS thresholds.
- PSPS: PG&E proposed remote grid solutions.
- PSPS: Propane generator deployment and emissions.

The WMP reporting process and cycle would benefit from additional refinements.

GPI reviewed the 2021 WMP Update plans submitted on February 5, 2021, by PG&E, SCE and SDG&E. Despite being defined as 1-year updates, these plans totaled upwards of 2,200 pages in total and contained new modeling methodologies that differed substantially from the 2020 WMP 3-year plans. The 2021 update plans also contained frequent references to the IOU's February 26, 2021, filings totaling over 500 pages, which were submitted just one month prior to the comment reporting deadline. The IOUs also filed their 2020 fourth quarter reports on February 5, 2021. Public comments on the 2021 WMP Updates and fourth quarter reports were granted an extension of 8 business days to March 29, 2021.

Our work was facilitated by the updated WMP filing and comment cycle that staggers the IOU annual update filings from the SMJU/ITO filings in an effort to reduce the volume of content requiring review. However, the volume of the February 5, 2021, IOU 2021 WMP Updates and Quarter 4 reports, February 26, 2021 filings, plus overlapping SMJU/ITO Update filings on March 5, 2021, still proved more than challenging for the allotted review time. We suspect WMP report volumes will decrease or at a minimum, stabilize over time as WMP methodologies mature. That being said, the substantial changes made between the 2020, 3-year WMPs, and the 2021, 1-year WMP Updates strongly suggest that electrical corporation's WMP's and methodologies therein remain relatively immature and continue to undergo substantial and even complete methodological overhauls.

Other challenges to efficient review included the disjunct or redundant content in the 2021 WMP Updates and the February 26, 2021, filings. Perhaps the largest issue was numerous references in the 2021 WMP Update filings (filed on February 5, 2021) to key outcomes and metrics in the February 26, 2021, filings (e.g. PG&E 2021 WMP Update, p. 345). The IOUs appeared to have used the February 26, 2021, filings as a time extension to complete multiple analyses and assessments relative to the annual WMP Update. Utility WMP updates also embed key background data in responses to deficiencies identified by the WSD (e.g. PG&E 2021 WMP Update, Section 4.6), which creates challenges for finding and evaluating data relevant to each mitigation described in later sections.

We recognize that annual update and quarterly report volume cannot be expressly dictated and is intended to provide a comprehensive and transparent window into the WMP methodologies. There are, however, two important aspects of WMP filings that could be improved upon: (1) eliminate a staggered release schedule for IOU deficiency responses (i.e. the February 26, 2021, filings) that contain key initiative outcomes important for reviewing annual WMP Updates; and (2) eliminate content overlap between the February 26, 2021, filing, the Annual WMP Update, and Quarter 4 report content by combining them to the extent possible. Consolidating all content to a standardized filing cycle (i.e. quarterly, annual, and 3-year filings) that includes deficiency responses could ease the burden and improve the efficiency of the annual review process. It may also be prudent to push the SMJU/ITO annual WMP Update filing and comment period out by 1- 2 weeks in order to allow stakeholders and the WSD additional time to thoroughly review the IOU and SMJU/ITO filings in sequence.

PG&E has limited ability to quantify wildfire risk mitigation capabilities and/or mitigate wildfire risk.

PG&E claims success based on achieving their program targets by the numbers. However, it is not clear whether many of the completed activities will make a substantial impact on PG&Es wildfire or PSPS risk. It is now known that PG&E's granular risk modeling methods outlined in their 2020 WMP contained numerous flaws that lead to incorrect identification of circuit wildfire risk. Evidence includes (*i*) the WSD's February 8, 2021, audit report on PGE's EVM work and multiple differing prioritization models therein; (*ii*) PG&E's workshop presentation on their updated risk rankings; (*iii*) content in their 2021 WMP Update which includes a new risk prioritization model; and (*iv*) the decision to scrap their previously used egress model. The February 8, 2021 WSD audit uncovered a series of proposed EVM locational prioritization models purportedly based on risk assessments. These models varied wildly in terms of individual circuit risk and prioritization rankings and included inconsistencies regarding the model/methods PG&E claimed to use versus those actually provided to the WSD in data requests.

During the IOU's 2021 WMP Update workshop presentations, PGE provided plots that showed their previous risk assessment and granular risk rankings were essentially inverse of those determined by the new method described in the 2021 WMP Update. PG&E also noted that distributed grid investments had minimal impact on reducing the impacts of PSPS in part due to substantive differences between granular PSPS risk and wildfire risk. PG&Es 2021 WMP update also states that their previous egress model, intended to identify important egress routes for the purpose of granular grid hardening and risk mitigation prioritization was flawed to the point of having to eliminate the entire model from use. In Section 7.3.1. on Risk Assessment and Mapping under "Future improvements to initiative" PG&E states:

> Distribution: In June 2021, PG&E intends to focus on understanding and better quantifying risk reduction of implemented mitigations on the distribution system and refining the 2021 Wildfire Distribution Risk Model. Refinements will include the added ability to compare wildfire risks for different risk drivers as well as measuring the risk reduction of specific mitigations. These refinements in 2021 will be represented in the 2022 Wildfire Distribution Risk Model.

This future improvement plan is vague and only goes so far as to set plans for achieving mitigation specific RSEs, which is a baseline WMP objective that has been an expectation for many years.

Risk assessment and granular risk modeling are foundational to determining the optimal locations for phased and efficient risk mitigation efforts that maximize risk reduction. It is also foundational to projecting the anticipated outcome of risk mitigation activities in terms of their ability to effectively reduce wildfire ignition and consequence risk and/or PSPS risk. The former issue, as to whether PG&E's completed, and proposed methods and mitigations are capable of actual wildfire risk mitigation is perhaps the most concerning. Given the drastically adjusted risk rankings from 2019/2020 to 2021, there is reason to suspect that the locations of other mitigation activities on PG&E's distribution system such as completed Covered Conductor (CC) and sectionalization grid hardening were not strategically implemented to reduce either wildfire or PSPS risk, similar to the WSD findings regarding EVM locations. Notably, PG&E reported very small reductions in customer impacts related to grid hardening, suggesting that sectionalization efforts and other grid hardening work was unable to substantially reduce PSPS risk (See topic 3 on PSPS risk modeling for additional discussion).

Given PG&E's complete risk assessment methodology overhaul, it is perhaps unsurprising that PG&E was essentially unable to project any decrease in ignitions for 2021 or 2022 in the 2021 WMP Update Tables 7.1 and 7.2. The lack of anticipated risk event outcomes suggests that PG&E is unable to actually project the risk reduction potential of different mitigations. This includes knowing locational risk for each risk driver and the efficacy of different mitigation activities for reducing the likelihood of each risk event type. This shortcoming also implies an inability to adequately compare risk mitigation alternatives for strategic locational deployment. PG&Es 2021 WMP Update reinforces this concern in regards to mitigation selection, stating:

> While PG&E needs to do more in evaluating how RSE scores can be leveraged into our strategic planning process for work prioritization and comparison of alternatives, in the near-term, PG&E is focused on refining on RSE modelling and increasing the number of RSE calculations across the initiatives. We have not performed a quantitative alternatives

> analysis on every initiative, some of which are very foundational and fundamental, like benchmarking with other utilities. At a minimum PG&E has considered not performing this initiative as a primary alternative, but in most all cases has at least subjectively evaluated that the benefits of performing the initiative outweigh the costs (PG&E 2021 WMP Update, p. 369).

PG&E also notes that its risk models are currently limited to Vegetation Probability of Ignition (V-POI) and Equipment Probability of Ignition (E-POI) which currently includes conductor failure drivers. Near-term plans include adding additional POI models informed by other risk drivers. The implications for risk mitigation planning and implementation suggests that PG&E is behind in terms of their ability to properly select and efficiently deploy a range of mitigations informed by quantitative risk reduction estimates. For example, PG&E is continuing to prioritize the replacement of CAL FIRE non-exempt fuses based on HFTDs. They anticipate this effort to take 7-8 years to complete (PG&E 2021 WMP Update, p. 487-488). They further state that their prioritization framework is evolving and future work will be based on the Technosylva models. The delay in developing more granular risk models is likely reducing the efficiency of risk reduction and limiting early buydown for this mitigation.

While PG&E acknowledges some of these shortfalls and continues to work towards filling their informational gaps, it also suggests a dire need for comprehensive risk assessment validation and vetting. Even though risk modeling methods are described in the WMP and WMP update, the specific outcomes of these methods as well as the annual application of the model outputs remain relatively opaque. This opacity masked multiple faulty risk model outputs that PG&E relied on to implement costly risk mitigation initiatives in non-ideal locations that as a result have reduced capabilities to effectively mitigate risk. The repercussions have also required that PG&E abandon a proportion of their planned 2021 mitigations in order to pivot to updated locations. This need to pivot has resulted in: (1) a loss of effective risk mitigation from 2019 and 2020 mitigation implementation activities; (2) a decrease in the amount and therefore rate of total mitigation deployment planed for 2021; (3) an ineffective use of ratepayer monies in 2020 due to less effective mitigations and in 2021 for replanning efforts; and (4) overall lost opportunities to reduce wildfire and PSPS risk for at least two years running (2020-2021).

GPI recommends a requirement that all electrical corporations, especially the IOUs, provide a summary of the annual planned locations of each mitigation and data-driven justifications for those locations. This could be part of the IE review process and summarized in the IE reports in order to delegate summary preparation while also managing the volume of the WMP Plans and Updates. PG&E should also clarity which POI risk drivers or asset-based models it will add to its overall Wildfire Distribution Risk Model in 2021. We also recommend additional risk model vetting described in more detail in the section below.

Risk Modeling and the risk of not getting it "right": Wildfire and ignition risk models require comprehensive and transparent vetting.

Granular wildfire risk models are foundational to deploying the proper risk mitigation types in locations that maximize risk reduction during phased annual deployment schedules over long timeframes (e.g. near-, mid-, and long-term). All IOU 2021 WMP Updates presented new or updated granular risk models that guide wildfire and/or PSPS risk mitigation efforts. As discussed above, PG&E's previous wildfire risk evaluation models are now known to have substantial flaws (See discussion in 2. above) to the point that they have been largely replaced with their new Wildfire Distribution Risk Model (WDRM) that includes both new ignition probability models and wildfire consequence models. All three IOUs are now using Technosylva's wildfire propagation and consequence model in their wildfire risk modeling in place of the Reax model. They have all also achieved an asset, and/or circuit-segment/circuit level wildfire risk assessment that utilizes Machine Learning (ML) techniques to predict ignition locations in conjunction with resultant wildfire consequence.

Both SCE and PG&E developed asset level probability-of-ignition wildfire risk models. However, there are nuanced differences between SCE's Machine Learning based model compared to PG&E's model that may increase its ability to predict wildfire risk. Namely differences in the dataset used to train the predictive risk models and in the subset of data used to test the model's predictive ability.

The richness and size of a dataset influences the ability of the resultant model to predict future occurrences of the target event(s). This is particularly the case for machine learning models which are used to learn and identify patterns in complex multi-variate datasets. These models require large datasets in order to adequately evaluate condition and outcome patterns. In the case of wildfire risk, this includes predicting when and where risk driver events will occur and which of those events will lead to ignitions based on the underlying system conditions (e.g. assert type and condition, weather, vegetation type, fuel load etc.). If the input dataset does not include a given condition-event occurrence, then the model cannot learn nor predict its occurrence.

For the IOUs the amount of available data for training and testing probability-of-ignition ML models for each event category (e.g. risk events, ignitions) varies depending on their unique conditions and territory size. Historically, ignition-risk events occur more frequently than ignitions by two-to-three orders of magnitude. PG&E experiences on average 40,651 risk events per year as compared to 424 ignitions per year based on their 2015-2020 data. SCE, which has a smaller footprint, experiences an average of nearly 14,000 risk events and 112 ignitions per year based on 2015-2020 data. SCE therefore trains and tests its ML model on risk event outage data totaling around 85,000 data points over its service territory. These outage data are attributed to assets and ignition potential based on sub-algorithms and assumptions. PG&E trained its ML wildfire risk model on 2015-2018 ignition data, suggesting a dataset of 1,656 data points over its service territory. Inherently, PG&E's data set has much less density, which suggests that it is capturing fewer condition-event combinations that are relevant to predicting ignitions across its service territory. PG&E noted during the workshops that its decision to use ignition data was to allow more granular asset-level modeling. GPI recommends that PG&E provide additional explanation as to whether their decision to use a less rich ignition data set may affect their ability to predict and prevent risk events that may lead to ignitions. Alternatively, or in addition, we recommend a third-party assessment of PG&E's ML probability of ignition models and the statistical limitations of the ignition-based training dataset.

SCE and PG&E performed model testing on a subset of the outage and ignition input data sets, respectively, to test the ability of the probability of ignition ML models to predict actual events. SCE did this by selecting a random subset of the total input dataset. PG&E performed a model validation/vetting test on 2019 ignition data (n = 441). In the opinion of the GPI, SCE's randomly populated test dataset is a superior method. First, it ensures that risk events associated with all available annual patterns (i.e. system conditions combinations, e.g. weather) are integrated into the model training phase. Second, the model test dataset includes a random sampling of all condition-event combinations from all annual patterns available (i.e. 2015-2020), and is not biased toward testing for risk events that took place during a single year with a narrow condition profile (e.g. weather pattern) on which the model was never trained. GPI recommends that PG&E adopt SCEs method for randomly selecting a training dataset from the total training-testing data set.

We also note that none of the IOUs provide the results of their probability-of-ignition ML model test. GPI recommends an update to the WMP filing requirements to include explicit instructions for providing a summary of wildfire risk model testing outcomes and uncertainty. The summary should include a description of false negatives (e.g. the model did not predict the occurrence of a known ignition in the test dataset). In future years it would be prudent to include a ML specialist on the IE teams that performs external reviews of the IOUs' ML risk models, including those aspects discussed above.

Risk Spend Efficiency is a complex metric that is dynamically linked to mitigation deployment.

It is increasingly understood that Risk Spend Efficiency (RSE) is a complex valuation linked to mitigation type, duration of efficacy, location, and type of risk mitigated (i.e. wildfire and PSPS). Additional key elements of RSE complexity that have yet to be evaluated are the impacts of overlapping mitigation deployment (e.g. co-deployment of CC and EVM) and the degree of deployment (e.g. 70 percent versus 80 percent CC coverage in a given risk zone). SCE is making progress towards assessing the risk mitigation potential of multiple, layered mitigation activities. However, all Utilities have yet to fully grasp the benefits, or lack thereof, of stacked mitigations. Similarly, the degree of mitigation deployment required before an RSE/ risk mitigation plateau is reached remains unknown. A combination of top-down system modeling and granular, bottom-up modeling may be required to grasp and guide mitigation threshold deployment decision making. While establishing a deadline for performing stacked mitigation benefits and coverage analyses may be premature, the Utilities should include these as long-term goals in their wildfire mitigation planning in order to guide work towards developing a more nuanced understanding of mitigation RSEs that also informs when a benefit plateau is achieved. For example, determining a plateau is not necessarily a signal to cease work, but may be used to redirect efforts to other mitigations (e.g. a shift from focusing on CC to other complimentary grid hardening approaches).

Utility mid- and long-term planning statements are still dominated by generalized visions and broad "goals" versus including more concrete objectives that guide planning decisions.

Utility long-term plans remain relatively vague and vision based. GPI suspects this is due to the relative immaturity of foundational wildfire planning elements such as granular risk models, the unknown and relatively untested impacts of deploying substantial covered conductor and other grid hardening initiatives on an unprecedented scale, and ongoing challenges in comparing mitigation strategies and evaluating stacked mitigation benefits. While we anticipate long-term WMPs to mature with foundational capabilities and knowledge this does not exempt the Utilities from defining these challenges as specific goals to overcome in their mid- and long-term planning statements.

GPI supports continued pressure on the utilities to establish more directed mid- and long-term planning strategies. These strategies should include goals to improve specific knowledge gaps that are limiting factors to method and plan maturity. For example, a mid- and long-term goal should include evaluating the operability of CC and other grid hardening initiatives under PSPS relevant conditions, including the coverage needed to enact new thresholds, and applying the findings to a long-term multifaceted PSPS reduction goal that includes strategic grid hardening in addition to the current focus on situational awareness weather forecasting, and sectionalizing. Another example would be developing an understanding of local, regional, and system-wide mitigation RSE plateaus associated with optimal coverage or deployment concentrations.

Utilities state that third party vetting occurred but often do not provide who the third parties are or summarize the results.

The IOUs state that third parties were engaged to review internal studies or models. However, they still often fail to provide who the third-parties and external experts were, their recommendations, and whether they were adopted going forward. For example, PG&E states:

> Working with external experts, PG&E Meteorology improved our operational weather model and historical datasets in 2020 by increasing the model granularity from 3 x 3 km to 2 x 2 km, and creating a new 30-year weather, dead fuel and live fuel moisture climatology at 2 x 2 km resolution (PGE 2021 WMP Update, p. 79).

There is also a general lack of QA/QC, validation and vetting results. For example, in regards to their transmission operability assessment model, PG&E outlines numerous QA/QC checks as well as in progress external reviews, but does not provide a summary of outcomes to date:

> As part of the Risk Assessment step in the Risk Modeling Framework, models are reviewed and validated. Validation is conducted on a number of Quality Assurance (QA) and Quality Control (QC) levels. Two QA methods are employed for validation. First, following good data science and software development practice, data scientists conduct code reviews on each other's work. Second, model runs include test automation code that checks model outputs to catch erroneous values. A number of QC steps are also employed both internal and external to PG&E. Within PG&E, the EORM team reviews the modeling methodology and results to provide feedback and signal its acceptance of the models for use in measuring risk. Next, PG&E groups that use the risk models to develop mitigation work plans test the model with their subject matter expertise. The PG&E Internal Audit group also has conducted in depth reviews of model methods, results and the application in developing mitigation workplans. Finally, PG&E uses outside expertise to review and validate model methods, code and model results. PG&E is currently contracted Energy and Environmental Economics, Inc. to perform a review and validation of the modeling methodology, code, model results and application to be completed in the spring 2021 (PG&E 2021 WMP Update, p. 139).

GPI recommends that the IOUs provide a quantitative and more functional qualitative summary of all model and method vetting and validation outcomes to date, from both internal and external evaluations. These should be included in the annual updates and 3-year WMPs.

The quality of information provided in Section 4.4.2 "Research Findings" varies widely.

Section 4.4.2 "Research Findings" requires that electrical corporations provide "Results and Discussion" summaries of their research findings to date as it relates to wildfire and PSPS mitigations. PG&E summarized three research studies covering external review of the HFTD maps, ongoing EVM improvements, and niche ignition events. While all valuable studies, PG&E did not provide adequate summaries within the results and discussion sections. These summaries are generally vague and contain no quantitative justification or statistical summaries. As an example, it would be relatively straightforward for PG&E to summarize the basis upon which "Redwoods and Douglas Firs were determined not to qualify as high-risk tree species…" SCE summaries one internal and one external study. The internal study only states that the Tree Risk Calculator under review was deemed "sufficient" without any quantitative justification (SCE 2021 WMP Update, p. 80).

SDG&E in contrast describes nine research efforts that contribute to a better understanding of Wildfire and PSPS mitigations. They also provide data tables and summaries based on statistical analyses within the Results and Discussion sections. These quantitative responses help evaluate the applied metrics and data underlying qualitative claims. In terms of content SDG&E's responses to Section 4.4.2 Research Findings should set the current bar for "best practices." We also appreciate that SDG&E acknowledged that data comparisons for projects 4.4.2.4 and 4.4.2.5 are not yet statistically significant. These data and corresponding summaries provide needed transparency into the status of ongoing mitigation evaluation work.

Table 1 data assessment: PG&E likely has numerous undiscovered Level 1, 2 and 3 "findings".

Inspections data from Table 1 provide insight into inspection coverage over HFTDs as well as the potential for yet to be identified Level 1 – 3 findings and outstanding HFTD asset risk. We analyzed data in data Table 1 as a way to explore indicators of existing and outstanding risk, and risk mitigation progress and trends for each Utility.

PG&E – PG&E reports a total of 25,223 overhead (OH) distribution circuit miles in HFTD. In 2020, PG&E completed 19,375 circuit miles of patrol inspections in HFTDs, totaling 77 percent HFTD OH distribution line coverage. Detailed and "other" inspections covered 52 percent and 8 percent, respectively, of PG&E's OH distribution lines in HFTD. Patrol inspection in HFTD recorded a total of 455 Level 1 findings (0.023 Level 1 findings per mile), while detailed inspections identified 1,868 Level 1 findings (0.142 findings per mile). The majority of these findings were recorded in the 3rd quarter. Interestingly, PG&E completed roughly the same patrol and detailed inspection line miles in the second and third quarters, yet discovered substantially more Level 1 findings per mile in third quarter inspections. HFTD Distribution OH Patrol inspection Level 1 findings totaled 0.002 per mile in Q2 versus 0.065 per mile in Q3. HFTD detailed OH inspection Level 1 findings totaled 0.030 per mile in Q2 versus 0.251 per mile in Q3. 2020 Patrol inspection Level 1 findings (0.023 Level 1 findings per mile) were also between 2 and 20+ times higher compared to all previous years (2015 – 2019, minimum = 0.000 Level 1 per mile in 2019, maximum = 0.009 Level 1 findings per mile in 2018).

The data in Table 1 do not appear to be explained by PG&E's response to Action PGE-21 (Class A) regarding "a small percent of E and F priority correction notifications…that have changed to an "A" or "B" priority rating…" in 2020 (PG&E 2021 WMP Update, p. 204). The increase in inspection findings may be somewhat explained based on PG&E statement that "Since 2019, distribution assets have been inspected more rigorously than in previous years through PG&E's WSIP (PG&E 2021 WMP Update, p. 536)." PG&E should clarify if their inspection and/or Level 1 criteria changed in 2020, and/or from 2020 Q2 to Q3; or if 2020 Q3 inspections took place in regions more prone to grid damage or were otherwise biased by other factors (e.g. asset age etc). It is concerning that the volume of PG&E's 2020 Level 1 findings may reflect a backlog of never addressed OH Distribution issues and that prior inspection methods were unable to identify these issues.

Based on the per mile Level 1 occurrence rate for Patrol and Detailed inspections in 2020 (0.023 and 0.142, respectively), and the total HFTD Distribution OH line miles not inspected, we can extrapolate the number of Level 1 findings that remain undiscovered on PG&E's HFTD Distribution OH lines. The result is an extrapolated 137 and 1,724 possible remaining Level 1 findings on HFTD Distribution OH lines that could be identified by patrol and detailed inspections, respectively. The number of potential outstanding Level 1 findings equates to 44 % of the total anticipated Level 1 findings (Sum(Level 1 not yet found)/ Sum(Level 1 discovered and not yet found)). Extrapolated, potential outstanding Level 2 and 3 Findings on HFTD Distribution OH lines from as yet to be completed HFTD detailed inspections total 2,801 and 65,150, respectively. These potential outstanding HFTD Level 1 findings, as well as many more HFTD Level 2 and 3 yet to be discovered findings, suggests substantial unidentified and unmitigated HFTD risk in PG&E's territory.

Table 1 also provides 2020 inspections findings from all distribution lines (e.g. HFTD and non-HFTD). An assessment of these values shows that in 2020 34 percent and 56 percent of all PG&E Distribution line Patrol and Detailed inspections by circuit mile, respectively, took place on HFTD Distribution OH lines. Data Table 1 line numbers 1.d.ii and 1.e.ii, titled "Level 1 findings for patrol inspections - Distribution lines" and "Level 1 findings for detailed inspections - Distribution lines", are referenced as not including Level 1 findings from HFTD Distribution OH lines. Normalizing non-HFTD Patrol and Detailed Level 1 findings to non-HFTD Distribution OH circuit-miles inspected (total – HFTD) results in a 2020 occurrence rate of 0.007 and 0.072 Level 1 findings per circuit mile in non-HFTD Distribution overhead lines, respectively. These data suggest that the per-circuit-mile occurrence of Level 1 findings on HFTD Distribution OH lines is 2 – 3.5 times higher than in non-HFTD regions. Applying this same assessment to Level 2 findings, there are approximately 2 – 3.5 times more Level 2 findings on non-HFTD Distribution lines (0.072 and 0.484 Level 2 per mile, respectively) compared to HFTD Distribution OH lines based on detailed and patrol inspection findings. In summary, the frequency of occurrence by circuit mile of Level 1 and 2 findings on HFTD versus non-HFTD Distribution lines are inverse.

The higher frequency of Level 1 findings on HFTD Distribution OH lines per circuit mile indicate that the highest risk findings are more concentrated in the highest wildfire risk regions (i.e. HFTD). Nevertheless, these regions are not inspected in their entirety on an annual basis. While it is understood that inspections apply to other risk reduction efforts in addition to wildfire risk mitigation, PG&E should explain why they are electing to perform nearly 50 percent of their detailed inspections on non-HFTD Distribution lines versus HFTD distribution lines with higher frequency of Level 1 findings. PG&E should also explain whether these 2020 findings are or will inform their inspection prioritization approach in 2021 and future years, especially in regards to detailed inspections, which appear to be an order of magnitude more effective at identifying Level 1-3 findings compared to Patrol inspections.

SDG&E – In 2020 SDG&E performed patrol and detailed inspections on 97 percent and 21 percent of its HFTD Distribution lines, respectively. These inspections recorded Level 1 findings at a frequency of 0.004 and 0.018 per circuit mile. While SDG&E's annual, HFTD distribution line detailed inspection coverage has remained relatively consistent (15- 25 percent) from 2015 through 2020, their Level 1 findings have decreased year-over-year along with the findings per mile frequency (from 0.320 to 0.018 Level 1 per mile from 2015 to 2020). The extrapolated number of potential outstanding HFTD Distribution Level 1 findings from HFTD Patrol and Detailed inspections that were not completed in 2020 totals 0.4 and 51, respectively, based on a 0.004 and 0.018 Level 1 per mile occurrence rate in 2020. HFTD Patrol and Detailed Distribution line inspections totaled 53 percent and 100 percent of all distribution circuit miles inspected for years 2015 through 2020. That is, all SDG&E Detailed distribution inspections took place in HFTDs. While PG&E performed Detailed inspections on a larger percentage of its HFTD

Distribution lines in 2020 (52 percent versus SDG&E's 21 percent in 2020), PG&E wildfire risk related to Level 1 findings is not diminishing, but rather increasing over time since 2015 on a per mile basis. PG&E's per mile occurrence for Level 1 findings from Patrol and Detailed inspections on HFTD Distribution lines is also around 10 times higher compared to SDG&E. Based on these data, SDG&E's per mile risk associated with Level 1 findings is lower in general, and is decreasing over time compared to PG&E.

SCE – Since 2015, SCE's data Table 1 entries suggest they completed annual Patrol inspections on over 100 percent of their HFTD Distribution lines. From 2015 – 2018, SCE performed Detailed inspections on an average of 24 percent of their HFTD Distribution lines. SCE has since increased their detailed inspection coverage to 163 percent and 173 percent of HFTD distribution lines. Table 1 Notes that SCE tracks inspections on an asset basis such that the reported HFTD Distribution circuit miles are estimated based on the average span length between structures times the number of structures inspected. Unless SCE is completing detailed inspections along their entire HFTD Distribution system almost twice per year, their circuit mile estimation method appears to be incorrect. Unfortunately, SCE inspection data per circuit "mile" is therefore not comparable to PG&E and SDG&E data. GPI recommends that SCE improve their asset-to-circuit mile conversion or directly collect data on circuit miles inspected. It is not possible to accurately evaluate what proportion of SCE's HFTD Distribution system is inspected by via patrol, detailed or other inspections.

We can however do a cross-Utility comparison of percent of total distribution inspections that occurred in HFTD. SCE has consistently preformed 25 percent of total Distribution Patrol inspections within HFTD from 2015 – 2020. From 2015- 2018, SCE completed an average of 27 percent of total Detailed Distribution inspections in HFTD, and increased this to approximate 73 percent in 2019 and 2020. Both SCE (73 percent) and SDG&E (100 percent) are now preforming a larger proportion of total Distribution, Detailed inspections in their HFTD compared to PG&E (56 percent). As stated above, PG&E should justify their Detailed inspection prioritization plan and explain how they will use their inspection findings to inform HFTD prioritization decisions.

Assuming SCE's annual data collection and asset-to-circuit-mile treatment is consistent, SCE has experienced a drastic decrease in Level 1 Findings per "mile" (or asset), from an average of 1.25 Level findings per "mile" between 2015 – 2018, down to 0.24 and 0.16 Level 1 findings per "mile" in 2019 and 2020. These data suggest that like SDG&E, SCE's risk related to Level 1 findings is decreasing over time. We cannot determine the number of potentially outstanding Level 1 findings since SCE's mileage estimations appear to be flawed. SCE appears to have found more Level 2 and 3 findings via Patrol inspections compared to Detailed inspections in 2019, though this relationship between inspection type and number of findings is inverse in 2020. SCE should clarify if this trend is the result of a methodological change or other inspection bias (e.g. locational bias) in their patrol and detailed inspections.

Additional data analysis notes – Total 2020 HFTD Distribution circuit miles were generated from data Table 8, lines 1.k, 2.k and 3.k to include HFTD Zone 1, Tier 2 and Tier 3 for WUI and non-WUI. Notably, total HFTD and non-HFTD Distribution and Transmission circuit miles listed in Table 8 do not add up to the sum of all "Circuit miles (including WUI and non-WUI)" (lines 1.a, 2.a, 3.a). This is the case for all utilities. There appear to be "missing" circuit miles for all utilities in Table 8, based on data in table rows 1.a, 1.i, and 1.k; 2.a, 2.i, and 2.k; and 3.a, 3.i, and 3.k.

PG&E Field Safety Reassessments

PG&E performs Field Safety Reassessments on some inspection findings in the event that they are unable to address them in the required timeframe based on the finding "priority" ranking or Level. PG&E states:

> Long term, it is expected that the volume of maintenance notifications generated through enhanced inspections will be executed in accordance with appropriate timelines associated with the damage found. Where notifications cannot be completed per the timeline, field safety reassessments (FSR) are conducted, and information will help to refine the understanding of the damage mode decay rates. This information will also be used to improve guidance to maintenance inspectors. Additionally, it is expected that effectiveness of maintenance will be trended and used to inform future maintenance mitigations, processes, and procedures (PG&E 2021 WMP Update, p. 535).

This comment and practice appear to suggest that PG&E is currently unable to repair or remedy all findings according to the assigned level of urgency. It further suggests that PG&E may be spending substantial time reassessing existing findings and down- or up-grading them based on these reassessments. PG&E should clarify how many reassessments it is performing each quarter and year, how this is affecting its ability to perform new annual inspections on as yet uninspected HFTD circuit-miles, and its plan for eliminating the need to reinspect assets as soon as possible. If re-inspections are substantially affecting the initial, annual inspection process, a "long-term" plan as proposed is inadequate. PG&E should also detail how they will efficiently remedy what seems to be a backlog of findings and prevent backlogs in the future.

Vegetation Management: PG&E's Tree Assessment Tool (TAT) and SCE's Tree Risk Calculator appear to be replacing certified arborists in VM and EVM decision making.

Validating and vetting these app-based VM and tree removal tools is especially important as the Utilities increasingly rely on them to inform mitigations in the absence of certified arborists. Action PGE-74, Class B, sought to address this very issue. PG&E provided a vague response regarding "how it verifies and improves the TAT", stating:

1) PG&E performs TAT field verification on 100% of trees tall enough to strike our electrical facilities as part of our EVM. In addition, PG&E will be working with external resources to study TAT effectiveness and improvement as part of our Target Tree Species Study. (See 4.4.1 Targeted Tree Species Study).

2) This Target Tree Species Study is planned to be completed by Q2 2022. In connection with the study, PG&E will set up a system for continuous monitoring of TAT for ongoing evaluation (PGE, 2021 WMP Update, p. 668-9).

This response is vague and fails to share filed verification results to-date or establish an implementable plan for app validation and iterative improvements. PG&E does not provide any validation or QA/QC results on their TAT. While PG&E reports that SME's have endorsed the tool, this does not explain whether there are known outstanding refinements needed or what level of testing and vetting the tool has undergone to date. PG&E does propose to use data from a "Targeted Tree Species Study" "to evaluate the performance of the species risk rating component of our Tree Assessment Tool (TAT) (PG&E 2021 WMP Update, p. 108)." However, this implies that they are not currently aware of how accurate the outcome of the "species risk rating" tool is compared to traditional or certified arborist assessments. It appears that PG&E is increasingly relying on the TAT, though results of TAT accuracy are not available or at least not provided.

SCE reported for its Tree Risk Calculator that:

> Methodology: An independent project team consisting of an arborist and distribution engineer evaluated a total of 376 trees using SCE's Tree Risk Calculator. The data accuracy of each record, including, but not limited to GPS, grid/circuit data, photographs, SCE general information, customer information, and tree assessment documentation was captured and reviewed. The arborist evaluated the key performance indicators for the tree calculator and its effectiveness….
>
> Results: The project arborist determined that the Tree Risk Calculator was an efficient field data collection tool, and the data collected was sufficient to determine if a tree poses a potential risk to electrical facilities (SCE 2021 WMP Update, p. 80).

SCE does not provide any quantitative results to substantiate this determination. A brief discussion of the results, statistical accuracy, and summary tables could substantiate the claim. However, the lack of actual results raises questions as to what "sufficient" is defined as and whether statistical summaries were developed based on the "data accuracy" and "arborist evaluated performance" assessments.

The IOUs should summarize the quantitative outcomes of validation/vetting efforts to date (e.g. percent accuracy or alignment with certified arborist determinations) regarding app based VM tools that are currently in use. The outcomes of planned tool assessments should be summarized in future WMP filings.

Vegetation Management: VM generated fuel load management and residue end-uses

Vegetation Management (VM) and Enhanced Vegetation Management (EVM) activities are producing large amounts of biomass residues that, if left in place, increase the dead and dry fuel load along rights of way. It is important to note that utility generated fuel load could influence wildfire consequence regardless of whether the wildfire was ignited by utility assets or other ignition sources. Routing cleared biomass as waste also has repercussions regarding landfill space. VM programs will continue to produce tons of biomass on an annual basis given the amount of necessary annual VM and EVM clearance work as well as expanded hazard and strike tree removal programs designed to manage ongoing tree die-offs. Biomass residues from these activities have a wide range of alternate potential end uses from utility-scale biomass generation and industry-scale pellet production to community and forest service firewood programs. Developing and adopting biomass residue pathways are in keeping with California and wildfire mitigation sustainability goals. However, IOU VM and EVM residue end-use programs appear to remain in their infancy.

PG&E Transmission line VM work is described as using lop and scatter methods in areas "inaccessible to machinery." Corresponding: "Table PG&E-7.3.5.1: 2020 Transmission Inspections" indicates that all miles of Transmission inspected in 2020 for every work category are deemed: "Areas inaccessible to machinery…" This raises questions regarding if and how PG&E determined that all Transmission lines inspected are inaccessible and therefore the VM biomass residues are treated with lop and scatter practices and are not cleared. PG&E also fails to provide information regarding the end-point use or disposal method of chipped biomass residues.

SDG&E notes a policy of chipping and complete slash removal except for larger material greater than 6 inches (SDG&E 2021 WMP Update, p. 265, 269, 271). The end-point for removed biomass residues is not provided. During the workshop, SCE noted that their VM and EVM program resulted in palm residues that are considered grasses versus woody biomass. SCE's 2021 WMP Update states:

> At the end of 2020 SCE procured a consultant to conduct a study for determination of best practices for fuel management. Results of the study are expected to provide a combination of risk-based and environmentally sound options for fuel management within SCE's diverse service area.
>
> Through 2021, SCE plans will review and analyze the results of the study and implement more regionally appropriate fuel management standards (SCE 2021 WMP Update, p. 260).

GPI looks forward to the outcomes of this study as a pathway to determining more sustainable VM residue treatment options for southern California utilities. In general, however, there are few existing programs described in the IOU's 2021 WMP updates that suggest progress has been made in regards to expanding their VM residue management approaches and end-use pathways.

Utilities are now building sophisticated data collection and management methodologies. It will therefore become easier for Utilities and their contractors to record the end-point-use of VM and EVM biomass residues via the addition of "check boxes" regarding how VM and EVM residues were treated (e.g. lop and scatter versus chipped) and their end point destination after utility work is completed (e.g. biomass facility, local or forest firewood program, wood product facility, or none, if residues were left in place). IOUs should provide a plan for how they will implement these or similar metrics in the VM data collection and management programs. GPI also recommends that Utility retained IE's be instructed to document and review how electric corporations treat and manage VM and EVM biomass residues and whether utility statements regarding vegetation residue treatments, and treatments related accessibility, are accurate. This work can be completed during and parallel to IE Vegetation Management audits and site visits. Results of this work will provide a third-party audit of biomass residue treatments options that are currently in use, as well as provide insight on untapped potential for establishing sustainable biomass use pathways.

GPI also remains concerned that important biomass residue end-use opportunities are easily overlooked since this aspect of the WMPs is embedded within larger Maturity Model capabilities including vegetation grow-in mitigation (Capability 24, WSD-011 Attachment 2.4, p. 33) and vegetation fall-in mitigation (Capability 24, WSD-011 Attachment 2.4, p. 34). Further, considerations for determining cost-effective uses for vegetation waste are not included until the highest maturity level, Level 4. Prior maturity levels stipulate biomass residue removal extent and timeframes but not end point use. This would suggest substantial lost opportunities between establishing more robust practices for clearing and removal the biomass at earlier maturity levels, and routing that same biomass to cost-effective end uses.

We are also concerned with qualifying maturity level questions in the Utility Survey regarding these capabilities and maturity scoring. Specifically, in order of discussion:

> E.IV.f Does the utility remove vegetation waste along its right of way across the entire grid? [Yes/No] [See also E.V.d]
>
> E.IV.h Does the utility work with local landowners to provide a cost-effective use for cutting vegetation? [Yes/No] [See also E.V.f]
>
> E.IV.i Does the utility work with partners to identify new cost-effective uses for vegetation, taking into consideration environmental impacts and emissions of vegetation waste? [Yes/No] [See also E.V.g]
>
> E.V.c Is vegetation removed with cooperation from the community? [Yes/No]
>
> E.IV.g How long after cutting vegetation does the utility remove vegetation waste along right of way? [See also E.V.e]

It is almost certain that Utilities will never remove vegetation residues along the right of way (ROW) across their entire grid even if a robust slash removal and end-use pathway program is established. That is, as stated, Utilities will likely always answer “no” to the binary Questions E.IV.f. and E.V.d. Moreover, they do not have to record any data on VM residue removal to answer this question because it is easy to assume and state that at least some Vegetation residue was not cleared along some proportion of their ROW. A more functional alternative to this question would inquire about percent of Utility ROWs that were cleared of Vegetation management residues or percent of removal from annual completed VM activities. This question structure also induces a requirement to record residue removal data in VM work summaries in order to appropriately respond. Similarly, Utilities can answer “Yes” to binary Yes/No questions E.IV.h, E.IV.i, E.V.f, E.V.g, and E.V. c if they have isolated instances of working with the community, local landowners, or partners to provide cost-effective end-uses for VM residues. This means a well-designed program capable of substantial and diversified end-use pathways is not required to "check this box". Lastly, questions E.IV.g and E.V.e endeavor to understand when VM residues are removed. We suspect the assumption is the sooner the better. While we don't disagree with this assumption at face-value, there may be instance where initially leaving residues in place and recovering them later supports additional concerted fuel load management efforts by utilities and third-parties. For example, community or forest service manages firewood collection programs that are launched post-utility VM work could provide a low-cost way to remove VM residues after the work is completed and the woody debris has begun to season.

These Maturity Model limitations, new developments and capabilities in VM data collection and management tools, and a general lack of VM residue management and end-use planning in the 2021 WMP Updates, all point to a need to restructure expectations for VM residue assessment in the WMP. GPI recommends introducing non-binary, scaled assessments of VM residue treatment methods and their end-uses in the Maturity Model and WMP. We also recommend a preliminary assessment by Utility retained WMP IE's in order to inform current best practices and document residue end-uses that are already established. These data will provide a baseline from which the Maturity Model and WSD expectations can build from to determine a suite of future goals related to fuel load management, VM residue removal, and sustainable residue end-use pathways.

Vegetation Management: Fuels management, herbicides, fire retardant and IVM effectiveness

Both SCE and PG&E refer to vegetation and fuel management strategies that invoke slow growing, "fire-resistant" vegetation. PG&E terms aspects of their program Integrated Vegetation Management (IVM) and Utility Defensible Space (UDS). The UDS program to remove dead fuels and "reduce, or adjust, live fuels" appears to focus on the use of fire-retardants and some herbicide application (PG&E 2021 WMP Update, p. 641, p. 839). However, there is little discussion on the details of this program, what has been tested to date, the progress of required permitting and NEPA reviews, and anticipated effectiveness, reapplication timelines, and cost effectiveness. Utility responses to questions during the February workshops suggested fire retardants may require annual reapplication. PG&E even states that "While PG&E does not have data to use, PG&E intends to provide rough estimations for RSEs for the February 26th submission to better represent this program (PG&E 2021 WMP Update, p. 643)." GPI is concerned that the proposed RSE values have little-to-no basis given the seemingly complete lack of existing evaluation metrics. GPI does not support the use of purely conjectured or qualitative RSE values in the WMP. While preliminary RSE estimates may be needed to justify exploring a new method, they should not be used to justify application beyond pilot testing.

PG&E and SCE also provide few details regarding proposed sustainable re-vegetation efforts. SCE states:

> …SCE has partnered with one of the USFS agencies on a program for sustained fuel management measures, e.g., putting in low-growing "utility-friendly" vegetation to undesirable tree species growth.
>
> SCE is currently exploring environmentally sound and cost-effective means to promote desirable, stable, low-growing vegetation that are resistant to undesirable tree species. These methods can include a combination of chemical, biological, cultural, mechanical, and/or manual treatments. The use of these methods can provide long-term cost reductions and reduce the risk of outages and fires while improving wildlife habitat (SCE 2021 WMP Update, p. 260-1).

PG&E provides only vague descriptions of how they are prioritizing their IVM program around Transmission lines, stating that IVM "Prioritization is based on aging of work cycles and evaluation of vegetation re-growth (PG&E 2021 WMP update, p. 634)." In general, SCE and PG&E do not provide descriptions of the extent of alternate vegetation testing in progress (e.g. acres, circuit miles), where the test is established, what evaluation metrics are being recorded and monitored, or whether they are conducting fire-hazard testing/assessments (e.g. ignition potential and fire consequence of test plots). The IOUs should fill in these plan details, particularly if pilot testing and/or full program deployment has already commenced.

SCE and PG&E fuel load management strategies appear to remain in the beginning stages of maturity and anticipated outcomes are largely scoped for mid and long-term planning phases, respectively. SCE's decision to contract a fuels management consultant to explore optimal fuel load management within their service territory is perhaps the most comprehensive pathway to exploring a range of fuel load management strategies. GPI recommends all Utilities establish an external consultant to evaluate existing assumptions and methods and to identify possible alternative fuel load management strategies relevant to their territory characteristics at this early stage of fuel management program design and testing.

Vegetation Management: Locational prioritization methodology and modeling

The WSD audit of PG&E's EVM program in 2020 identified major issues with work prioritization. Much of the work was completed on circuits identified as lower-risk instead of high-risk circuits. The risk prioritization model and circuit ranking also changed numerous times over the course of work. PG&E is now establishing a "revised… internal incentive metric associated with EVM work to require that at least 80 percent of the work be performed in the top 20 percent of the risk ranking of circuit segments (PG&E 2021 WMP Update, p. 47)." This new objective is also established for other wildfire mitigations, such that PG&E states:

> Leveraging this new risk model, going forward at least 80 percent of our largest wildfire mitigation investments, System Hardening and Enhanced Vegetation Management, will be performed in the top 20 percent of the highest risk circuit segments or in fire rebuild areas (PG&E 2021 WMP Update, p. 229).

Numerous aspects of this goal remain opaque. First, it is unclear why PG&E requires an internal incentive program in order to guide where EVM work takes place. Presumably there should be or is a central decision authority that schedules and assigns EVM work, including work location, regardless of whether the work is completed by PG&E employees or contractors. PG&E references a newly formed "Wildfire Risk Governance Steering Committee." PG&E should expound on how this committee selects and directs the location of EVM and other mitigation activities. PG&E should also explain why an incentive program is needed to ensure that wildfire mitigation work is completed in the "right" places.

Second, the determination of 80 percent of work on the top 20 percent of risk ranked circuit-segments appears arbitrary for guiding EVM or other wildfire mitigations. The Utilities note that VM and grid hardening work occurs more regionally versus on narrowly targeted high-risk circuit-segments. However, PG&Es WMP Update does not provide justification for selecting the top 20 percent of risk ranked circuit segments or 80 percent of planned work as targets. PG&E should also clarify what proportion of the top 20 percent of risk-ranked circuit-segments would undergo EVM and other grid hardening work assuming 80 percent of work is completed therein. That is, would only 5 percent of the top 20 percent of risk ranked circuit-segments be addressed by an 80 percent of total work target? If the top 20 percent of risk ranked circuit-segments represent 90 percent of the total wildfire risk, what is the actual risk buy down of this proposal? We suspect the risk buydown could vary widely depending on these factors and which of the "top 20 percent" of circuit segments are worked.

Alternatively, would performing 80 percent of total wildfire mitigations in the top 5 percent or 10 percent of risk-ranked circuit segments result in more efficient and rapid risk buydown? Will work locations be initially selected based on the highest-ranking circuit-segments (e.g. in order) and extend to the surrounding regions to balance efficiency? PG&Es supposed progressive and targeted approach to locational prioritization of EVM and grid hardening appears productive at first blush, yet the underlying justification and anticipated risk reduction outcome must be evaluated in order to determine whether it is an effective risk reduction strategy.

Third, PG&E should clarify if circuit-segment risk rankings for EVM versus system hardening are distinct or one in the same. It is likely that there is combined risk reduction benefit from overlap between EVM and some system hardening efforts. System hardening does however include a wide range of mitigations. It is likely that some risk-ranked circuit-segments are dominated by vegetation risk, while others are dominated by, or have elevated asset condition related risk. PG&E should clarify if model-based risk driver contributions will inform the selection of circuit-segments in specific need of EVM versus system hardening work within the top 20 percent risk ranking for the proposed 80 percent of total mitigation work. Alternatively, will the proposed 80 percent of work within 20 percent of the top risk-ranked circuit segments not include additional circuit-segment targeting in alignment with specific mitigation activities.

PG&E should explain why the cost of Transmission substation defensible space work is increasing.

PG&E states:

> As of December 31, 2020, 100 percent of substations (40 of 40) located in these areas have attained defensible space. In 2020, PG&E spent $1.7 million and in 2021, we are planning to spend $2.5 million on defensible space for transmission substations (PG&E 2021 WMP Update, p. 531).

PG&E should explain why the budget for Transmission substation defensible work is increasing in 2021 if it already established defensible space in 2020 for all transmission substations. If the scope of work is equivalent to or less than what was completed in 2020, the costs should not increase substantially in 2021. Cost of work could decrease if work from 2020 is leveraged (e.g. less grubbing required in subsequent years).

PSPS: All electric corporations should develop PSPS risk models at a circuit-level granularity or better to inform initiative selection and prioritization.

The IOUs' 2021 WMP Updates indicate that the majority of their PSPS risk event and impact reduction are reliant on granular weather modeling. Sectionalizing as a PSPS mitigation is tightly linked to the granular weather modeling in order to only deenergize those circuits that are affected by high winds and high Fire Potential Index (FPI). There are currently multiple systemic shortcomings within this plan and related IOU planning capabilities including: (a) Granular weather modeling is a reactive mitigation that does not inherently improve the ability of the system to withstand higher winds or reduce ignition potential under high FPI conditions; (b) Sectionalization is a reactive PSPS mitigation and its effectiveness is dependent on implementing it in optimal locations – however granular PSPS risk models are in their infancy; (c) The inherent ability for other grid hardening and mitigation efforts (e.g. CC and EVM) to mitigate wildfire risk under PSPS conditions and therefore raise circuit/segment PSPS thresholds remains unknown;

(d) The effectiveness of other grid hardening and mitigation efforts to reduce PSPS risk is contingent on locating them in PSPS risk locations; and (e) It is not yet known what degree of grid hardening and other mitigation deployment are required to realize PSPS reduction benefits.

Granular weather monitoring and forecasting is a reactive mitigation that does not inherently improve the ability of the system to withstand higher winds or reduce ignition potential under high FPI conditions. The majority of IOU PSPS risk mitigation efforts are focused on predicting risk events (e.g. RFWs, high wind days, high FPI days) in order to better target PSPS event locations. This approach solidifies PSPS as an ongoing need. Even though customer impacts may be reduced, the focus is on determining when and where to implement PSPS. This focus on reactive PSPS implementation does not inherently bolster the grid to reduce wildfire risk by improving its ability to inherently reduce risk events or ignition probabilities during high winds, high FPI, or RFW events. Utility PSPS impact mitigation efforts will rapidly reach a mitigation plateau if they remain largely focused on granular weather forecasting.

Sectionalization is also a reactive PSPS mitigation, and its effectiveness is dependent on implementing it in optimal locations. Granular PSPS risk models, however, are still in their infancy. This means that higher granularity weather forecasting is only effective insofar as sectionalizing grid hardening is implemented in parallel and in optimal locations. This requires robust and granular PSPS risk modeling in order to inform optimal locations to deploy sectionalization. Benefits are also limited based on grid configuration and the degree of radial versus distributed generation resources. The foundational and most controllable initiatives needed to realize the benefits of more granular weather monitoring/forecasting are granular PSPS risk models to inform where sectionalizing and distributed energy resources, including microgrids, should be installed. Deploying these mitigations in the wrong places could render the investment ineffective. The IOUs also noted in the workshops that PSPS risk and wildfire risk are not necessarily co-located, such that using wildfire risk models to guide PSPS risk mitigation initiatives such as sectionalizing does not lead to optimal locational deployment. Without robust, granular PSPS risk models, the utilities are blindly deploying grid hardening strategies with limited ability to reduce PSPS events and resulting impacts.

To date, SCE and SDG&E have established new models capable of granular PSPS risk quantification. GPI recommends conducting a third-party verification and validation of SCE and SDG&E's granular PSPS risk models, given the near-term importance of sectionalization and DER deployment locations in terms of their ability to reduce PSPS impacts. PG&E's ability to model granular PSPS risk is lagging and their description of PSPS locational risk evaluation is highly generalized (e.g. PGE 2021 WMP Update, p. 505). We are especially concerned with PG&E's consideration of PSPS as a secondary risk, stating:

> PG&E also considers secondary risks and benefits as part of the System Hardening Program effort such as PSPS impacts, egress/ingress routes to support fire department response times and public safety, past fire history and effects on available fuels, current system condition, environmental risks to reconstruction activities, and general accessibility considerations to enhance employee safety (PG&E 2021 WMP Update, p. 559).

GPI recommends an interim, third-party assessment of PG&E's granular PSPS risk assessment and location selection method for sectionalization, DER deployment, and other system hardening locational prioritization. We also recommend establishing a deadline for PG&E to develop a quantitative, circuit or circuit-segment-level PSPS risk model.

The reactive PSPS mitigations described above will inevitably reach a PSPS reduction floor, since they do not improve the grid's ability to operate during the conditions that call for PSPS events. Electric corporations will have to bolster the ability of the grid to operate under high winds and high FPI conditions in order to reduce the need for PSPS altogether. The ability for other grid hardening and wildfire risk initiatives (e.g. covered conductor, pole replacements, line slap mitigations, EVM) to mitigate the need for and impacts of PSPS is reliant on knowing three overarching aspects: (*i*) The inherent ability for other grid hardening and mitigation efforts (e.g. CC and EVM) to mitigate wildfire risk under PSPS conditions and therefore raise circuit/segment operating/PSPS thresholds;

(*ii*) Granular PSPS risk informed mitigation deployment; (*iii*) The degree of grid hardening and other mitigation deployment required to realize PSPS reduction benefits (e.g. 80 percent CC coverage in a PSPS event zone). These aspects are also key components to determining the actual RSE of these mitigations in locations with PSPS risk. SCE appears to have made the most progress towards assessing the ability to raise circuit windspeed thresholds based on CC installations (SCE 2021 WMP Update, p. 344).

Our recommendations regarding a need for granular PSPS risk modeling as well as model vetting and validation, discussed above, are applicable to all system hardening mitigations. In addition, GPI recommends establishing a deadline for utilities to perform a comprehensive assessment of the ability of grid hardening initiatives to increase operating thresholds. There will likely be an ongoing need for analyses regarding the degree of grid hardening deployment needed to elevate grid operation/PSPS thresholds. While this may be an ongoing effort, the Utilities thus far have only provided vague estimates, little-to-no data, and generalized and equivocal plans to conduct the research needed to quantify the ability for grid hardening to raise PSPS thresholds and reduce PSPS impacts. Similarly, there is no known end-goal for the coverage of grid hardening needed either within a concentrated zone (e.g. high, medium or low wildfire or PSPS risk areas) or HFTD wide. Developing an "end-goal" for grid hardening mitigations will also support more detailed long-term prioritization and implementation planning beyond the current 2-3 year planning horizon.

PSPS: Post PSPS inspection findings should inform the evaluation of otherwise masked risk events to guide PSPS thresholds.

PSPS events result in a risk event and ignition data gap during the highest wind and fire risk days. This data gap masks the ability to evaluate the occurrence of outage types and risk drivers. While PSPS events eliminate the risk of Utility ignited wildfire, the lack of data during these events introduces challenges to evaluating PSPS thresholds and hinders the ability to develop alternative solutions that ultimately reduce or eliminate the need for PSPS. SCE notes that post-PSPS inspections found evidence for 60 counts of *potential* risk and/or ignition events (SCE 2021 WMP Update, p. 11). In the February 22, 2021, workshop PG&E noted that lines with CC incurred less damage after experiencing high winds and improved reenergization times and stated that they are working towards quantifying the benefits. All utilities perform post PSPS event inspections prior to reenergizing the lines. GPI recommends that all IOUs explain if and how they are using post PSPS inspection data to inform risk incurred during PSPS events with the end goal of evaluating PSPS thresholds and/or exploring alternative solutions.

PSPS: PG&E proposed remote grid solutions

PG&E proposes a potential alternative for PSPS that involves removing customers from the grid and establishing off-grid or remote grid solutions:

> In addition to potential Remote Grid facilities, PG&E is pursuing additional alternative configurations to eliminate the need to harden or rebuild overhead distribution lines in fire-prone areas. The alternative models include the option for PG&E to provide an incentive payment, tied to discontinuance of utility service, that would be sufficient to enable a customer to purchase and maintain its own SPS. If this option for self-provision proves preferable to a PG&E Remote Grid solution for some customers, then it could improve the portfolio reach of the Remote Grid Initiative by enabling broader customer agreement (PG&E 2021 WMP Update, p. 577).

PG&E should provide evidence of customer support for removal from the grid as a long-term solution to reducing or eliminating PSPS risk.

PSPSP: Propane generator deployment and emissions

PG&E and SDG&E appear to be moving toward renewable generation and batteries as the source of local distributed generation during PSPS events (e.g. SDG&E 2021 WMP Update, p. xiii). However, SCE continues to focus on diesel generators to provide PSPS backup power, though their individual customer support programs are battery focused and potential commercial customer-hosted microgrids would include solar generation. PGE's potential metrics for Remote Grid Deployment include tracking: "CO_2 Emissions from Standalone Power Systems (PG&E 2021 WMP Update, p. 319)." GPI supports this proposal and recommends that all IOUs estimate CO_2 emissions associated with distributed generation deployed to address PSPS impacts. Measuring the impacts of

PSPS-caused DG in CO_2 emissions aligns with statewide and energy sector greenhouse gas emission reduction goals and can inform whether GHG emissions associated with PSPS events call for alternative mitigations beyond the IOUs current renewable DG plans.

Conclusions

The 2021 WMP Updates in many ways more closely resemble new WMPs than updates. The utilities are clearly still in the developmental stage of planning and carrying out wildfire mitigation plans and measures, indicating an ongoing need for strong WSD oversite of the process. The GPI performed detailed analysis of key parts of the WMPs and report our findings herein.

The GPI urges the Commission to adopt our analyses and recommendations.

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Respectfully Submitted,

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