JENNER & BLOCK LLP
Reid J. Schar (*pro hac vice*)
RSchar@jenner.com
353 N. Clark Street
Chicago, IL 60654-3456
Telephone: +1 312 222 9350
Facsimile: +1 312 527 0484

CLARENCE DYER & COHEN LLP
Kate Dyer (Bar No. 171891)
kdyer@clarencedyer.com
899 Ellis Street
San Francisco, CA 94109-7807
Telephone: +1 415 749 1800
Facsimile: +1 415 749 1694

CRAVATH, SWAINE & MOORE LLP
Kevin J. Orsini (*pro hac vice*)
korsini@cravath.com
825 Eighth Avenue
New York, NY 10019
Telephone: +1 212 474 1000
Facsimile: +1 212 474 3700

Attorneys for Defendant PACIFIC GAS AND ELECTRIC COMPANY

UNITED STATES DISTRICT COURT
NORTHERN DISTRICT OF CALIFORNIA
SAN FRANCISCO DIVISION

UNITED STATES OF AMERICA, Plaintiff, v. PACIFIC GAS AND ELECTRIC COMPANY, Defendant.	Case No. 14-CR-00175-WHA **RESPONSE TO FIFTH FURTHER REQUEST FOR RESPONSES RE DIXIE FIRE** Judge: Hon. William Alsup

Defendant Pacific Gas and Electric Company ("PG&E") respectfully submits this response to the Court's Fifth Further Request for Responses re Dixie Fire dated November 3, 2021 (Dkt. 1504).

Question 36:

When the Court asks a question, PG&E should also ask its employees and contractors to learn about a topic or what happened. It is not sufficient to respond that PG&E has "not located any documents" on a topic, as PG&E did, for example, in responding to Question 12 (Dkt. 1479). When the answer helps PG&E, it readily, the Court has observed, supplies declarations and statements. PG&E should do the same regardless of whether the answer helps it. Therefore, PG&E shall go back and answer in full Question 5 (Dkt. No. 1428 — explain exactly what made the Bucks Creek 1101 circuit ranked eleventh most dangerous for equipment risk. Name the equipment, its precise location, what made it risky, and why it was not replaced before July 13, 2021); Question 15 (Dkt. No. 1479); and Question 18 (ibid. — the Senior Manager of the Distribution Planning Group should explain: if the data did not confirm or preclude a low-amperage, high-impedance fault, explain the possible interpretations that the data did suggest).

PG&E Response:

The Court asked for additional information concerning questions 5, 15 and 18. PG&E responds as follows:

Question 5 (Dkt. 1417): The circuit was ranked 11 out of 3,635 circuits with respect to the Equipment Risk. Please state each reason the circuit received such an elevated risk rating.

In 2021, the segment of the Bucks Creek 1101 Circuit where the tree fell, Bucks Creek 1101 CB, was ranked 11 of 3,635 circuit segments using the 2021 Wildfire Distribution Risk Model (the "Model").[1] The 2021 Model assesses the risk of wildfire ignition, spread and consequence associated with equipment failure related to the approximately 25,000 miles of overhead distribution conductor facilities in the High Fire Threat Districts Tiers 3 and 2.

[1] The 2021 Wildfire Distribution Risk Model is discussed in PG&E's 2021 Revised Wildfire Mitigation Plan ("WMP") at pages 130-135.

For purposes of assessing risk and targeting wildfire mitigation work more effectively, the 2021 Model segments its distribution circuits into Circuit Protection Zones ("CPZs"). As explained in the 2021 Wildfire Mitigation Plan ("WMP"), CPZs are the smallest non-overlapping sections of the distribution grid that can be de-energized.[2] PG&E ranks each CPZ separately, for the purposes of prioritizing System Hardening (e.g., covered conductor, undergrounding or Remote Grid) using the "Equipment Risk Model," and for enhanced vegetation management ("EVM"),[3] using, *inter alia*, the "Vegetation Risk Model." The Equipment Risk Model is comprised of two sub models: one that produces a Probability of Ignition ("POI") from equipment failure, and a second that simulates the Consequence of Ignition ("Wildfire Consequence"). PG&E considers these to be the components of the wildfire risk formula:

Wildfire Risk = Probability of Ignition x Wildfire Consequence

The Probability of Ignition for each CPZ is derived using a machine learning regression model to examine a number of covariates, or variables, associated with PG&E's overhead distribution conductors, and environmental and weather conditions in the specific area where the conductor is located, against known historical ignition events to produce a relative occurrence rate, i.e., a Probability of Ignition. The covariates considered in the Equipment Risk Model and their permutation importance are detailed in PG&E's 2021 WMP at pages 133 – 135, and in Table 4.5-3, on page 165.

In 2021, for the Bucks Creek 1101 CB, the Probability of Ignition ranking was 181. The reasons for this Probability of Ignition ranking were as follows. This circuit segment ranked in the top (i.e. higher probability or most risky) decile for precipitation average (due to low precipitation), the conductor material used on the line (copper, which has a higher likelihood of failure relative to other conductor material), and the maximum tree height in the segment. This circuit segment also ranked in the top quartile for the size of the conductor used on the line (#2

[2] Revised 2021 WMP, p. 736.

[3] Revised 2021 WMP, p. 173.

copper) and the age of the conductor present on the line (44 years). The Equipment Risk Model is focused specifically on the potential for equipment failure related to overhead conductor used on the line rather than specific components of, or structures on, the overhead distribution system. Thus, there is no individual piece of equipment within the circuit segment that drives the Equipment Risk Ranking.

With respect to the Wildfire Consequence estimation in the 2021 Model, PG&E uses the Technosylva fire modeling simulation software to estimate fire propagation in terms of rate of spread, flame length, and fire intensity known as Fire Behavior Index ("FBI," an index of rate of spread and flame length); and wildfire consequence in terms of estimated acres burned, structures impacted, and population impacted using an 8-hour fire simulation (assuming no suppression) based on estimated ground fuel conditions and historical elevated fire weather conditions. These "natural units" are then converted into a Multi Attribute Value Function ("MAVF") score in line with PG&E's 2020 Risk Assessment and Mitigation Phase ("RAMP") Report,[4] and the 2018 Safety Model Assessment Proceeding ("S-MAP") Settlement Agreement.[5] This simulation output scored the area occupied by the Bucks Creek 1101 CB as 3,512 MAVF points which was ranked at 200, driven by elevated acres burned and FBI score. PG&E discusses the Technosylva Fire Consequence in its 2021 Revised WMP at pages 160-161.

The overall risk score is calculated by multiplying Probability of Ignition (0.000265) by Wildfire Consequence (3,512) to produce a risk score of 0.735 MAVF points (to three significant figures). This score produced an overall risk rank in the 2021 Equipment Risk Model of 11 (of 3,635 circuit segments). A third party consultant validated PG&E's Model and concluded that the POI methodology and model was "fit for purpose." The third party report was shared with OEIS as part of the 2021 Wildfire Mitigation Plan revision, and referenced at page 154.

---

[4] A.20-06-012

[5] D.18-12-014

The 2021 Model was approved and the risk rankings were finalized in November 2020. PG&E moved swiftly to address the circuits whose risk ranking had increased, including Bucks Creek 1101 CB (its risk ranking for system hardening in the 2019 model is 1365, much lower relative to its 2021 ranking). Because of the 2021 risk rank, PG&E identified the Bucks Creek 1101 CB CPZ as a priority for system hardening and quickly began to develop a plan to harden this circuit, which was approved in January 2021. Due to various factors, including weather and multiple agency dependencies (including railroad, CalTrans, U.S. Forest Service, Cal Fire, and local counties), the project was slated to start construction in 2022. *See* PGE-DIXIE-NDCAL-000017019 at 3.

Question 15 (Dkt. 1470): Is PG&E in possession of any information from any source concerning the extent to which Douglas Firs conduct electricity? If so, state all such information in summary form and separately provide the back up.

In order to respond to the Court's original question as to whether the company possessed information concerning the extent to which Douglas Firs conduct electricity, PG&E interviewed employees in several departments that might have relevant information, including vegetation management, pole procurement, and advanced technology services. None of the employees interviewed were aware of any studies or information concerning the extent to which Douglas Firs conduct electricity. Neither the ISA manual for Utility Tree Risk Assessment nor the Cal Fire guide referenced by the Court ranks trees according to the extent of their conductivity or suggests that the relative conductivity of various species is a significant factor from a vegetation risk perspective. The pole procurement department reports that Douglas Firs are used as utility poles because of their strength, not because of their relative conductivity; insulators are used to prevent conductors from transmitting electricity to poles, whether made of wood or metal. Finally, PG&E's testing department was unaware of any studies of, or information concerning, the relative conductivity of Douglas Fir or of various species of wood.

PG&E has made a reasonable effort to locate information, if any, in its possession concerning the extent to which Douglas Fir conducts electricity, and has not been able to locate such information in its possession.

> *Question 18 (Dkt. 1470), per Dkt 1504 — the Senior Manager of the Distribution Planning Group should explain: if the data did not confirm or preclude a low-amperage, high-impedance fault, explain the possible interpretations that the data did suggest.*

The data referenced in PG&E's prior response to Question 18 (Dkt. 1479) is the July 13, 2021 phase load data for the Bucks Creek 1101 Line that was recorded in PG&E's Process Information ("PI") Historian database (*see* Attach. 1 to Dkt. 1444-5). PG&E and its Senior Manager of the Distribution Planning Group agree that this phase load data could reflect nothing but the ordinary usage of power by facilities served by the Bucks Creek 1101 Line. This phase load data also could be consistent with *both* ordinary usage of power by facilities served by the Bucks Creek 1101 Line *and* power flowing through a low-amperage high-impedance ground fault (*see* PG&E's Response to Question 6, Dkt. 1474). The load data itself does not indicate a ground fault. In other words, a low-amperage high-impedance ground fault can be consistent with the normal appearance of the load reflecting normal usage. While Cresta Dam and the tunnel apparently lost power from the Bucks Creek 1101 Line at the time of the 6:48 a.m. phase-to-phase fault event, PG&E is not aware of any evidence that users located upstream of Fuse 17733 experienced any interruption to their electrical service at that time. These upstream users include the three metered facilities belonging to the railroad, as well as the Bucks Creek Powerhouse (a part of PG&E's hydro-generation facilities).[6] All three phases of the Bucks Creek 1101 Line served these users.[7]

---

[6] The available evidence indicates that these upstream users did not lose power at the time of the 6:48 a.m. event on July 13. The one Smartmeter at a railroad facility on the Bucks Creek 1101 Line that was in communication with the PG&E Smartmeter network did not lose power until 8:00 p.m. on July 14. And the Rock Creek Switching Center likewise did not receive an alarm indicating a loss of power from the distribution line to the Bucks Creek Powerhouse until 8:00 p.m. on July 14. 8:00 p.m. on July 14 is the time when, according to PG&E's records, the line recloser was opened and the entire Bucks Creek 1101 Line was de-energized.

[7] The Bucks Creek Powerhouse used a three-phase transformer. And, while each of the three railroad facilities used a two-phase transformer, the best evidence available to PG&E at the present time indicates that one railroad facility was served by Phases A and B, another was served by Phases

The drop in the loads on each of the three phases of Bucks Creek 1101 Line at and following 6:48 a.m. is consistent with the loss of power at Cresta Dam and the tunnel. The continued but reduced loads on each of the three phases following 6:48 a.m. is consistent with the continued normal usage of power by the three railroad facilities and the Bucks Creek Powerhouse.[8] The absence of any apparent drop in the loads on any of the phases at or around 5:00 p.m. on July 13—the time at which the Dixie Troubleman opened the third fuse at Fuse 17733 and cut off all power potentially flowing to the tree on the line—or when Switch 941 was opened thereafter is likewise consistent with the load being due to upstream users.

None of the foregoing precludes the possibility that, prior to 5:00 p.m. on July 13, a portion of the load on Phase A was in fact flowing through a low-amperage, high impedance ground fault caused by the tree on the line (or any other such fault). The RT SCADA system itself, and the PI Historian system, each applied a protocol to the load data for the Bucks Creek 1101 Circuit such that it only reported (RT SCADA) or recorded (PI Historian) a new value if the load value for a phase changed by more than one amp from the prior reported (RT SCADA) or recorded (PI Historian) value.[9] It therefore is possible that some change in load less than one amp did occur following the opening of the third fuse at Fuse 17733 or the opening of Switch 941 (or at any other time), but is not reflected in the reported and recorded load data.

Question 37:

> *At the hearing, the Troubleman testified that he did not have authority to cut power at Switch 941 (a district operator "ha[s] to give me an okay to operate unless it's due to life or limb"). But even a single fuse blowing*

B and C, and the third was served by Phases A and C. *See* PG&E's Response to Question 33 (Dkt. 1502); PG&E's Response to Question 50 below (part "a").

[8] It is possible that some power also was being used by temporary work trailers at the Bucks Creek 1101 substation at that time. PG&E has not completed its investigation of this possibility.

[9] Application of a similar protocol is standard data management and, in the case of PI Historian, to compress data storage. Because the normal loads of the Bucks Creek 1101 Line are so low, RT SCADA reported changes whenever they exceeded one amp. For most of PG&E's distribution lines, where normal loads are far higher, RT SCADA will only report changes when they exceed five amps.

> *could cause single-phasing. According to PG&E, "Switchmen are not authorized to open primary devices to isolate trouble without first contacting the Control Center, except if single phasing is present" (Dkt. No. 1479, Exh. LL-1 at 32). Explain the discrepancy between the testimony and PG&E policy. Explain what training the Troubleman did or did not have with respect to PG&E's policy. The Troubleman must explain, under oath, his error in understanding the policy.*

PG&E Response:

PG&E respectfully submits that there is not a discrepancy between, on the one hand, the Dixie Troubleman's testimony (and conduct) and, on the other hand, PG&E's policy.

As previously reported, and as stated expressly in PG&E Procedure TD-2908P-01, the Dixie Troubleman did not have authority to open primary devices to isolate trouble unless there was single phasing or to protect life or property in an emergency situation. "Switchmen are not authorized to open primary devices to isolate trouble without first contacting the Control Center, except if single phasing is present or as stated in TD-2700-10 'Electric System Emergency Response Protocol', Section 1, to protect life or property during emergencies." PG&E Utility Procedure: TD-2908P-01, p. 32 (Ex. LL-1, Dkt. 1479-1). The procedure does not authorize troublemen to open devices upstream of the fuses to address single phasing without first contacting the Control Center. The Dixie Troubleman's conduct is consistent with this procedure.

As explained in the attached declaration from the Dixie Troubleman (Ex. DDD), prior to arriving at the pole supporting fuse 17733, the Dixie Troubleman did not know there was single phasing.[10] The fact that he could see with his binoculars that at least *one* fuse had apparently opened did not mean that the other fuses had remained closed—something he could not see. When he arrived at the pole, he could see that two fuses had operated and one fuse remained closed. At that point, as he explained in his testimony, he immediately opened the third fuse. To shut off power at Switch 941—upstream of the fuses—he would have needed to check with the Control Center.

[10] Nor, for the reasons set forth in the Dixie Troubleman's declaration, did he believe the equipment at the dam or tunnel was at risk from single phasing. *See* Ex. DDD ¶ 5.

As reflected in the attached declaration of the Dixie Troubleman, the Dixie Troubleman received training on this point.

Question 38:

After learning, at 14:43, that at least one fuse had blown; that the Troubleman would have difficulty and delays reaching the fuse; and that there was limited cell and radio service, what explanation(s) did the NDCC Operator #2 think was causing the outage, or possibly causing the outage, such that it was prudent not to cut power? Same question, for the Troubleman (Dkt. No. 1474, Exh. JJ-11). Provide sworn answers.

PG&E Response:

NDCC Operator #2 is an Apprentice Distribution Operator, working under the supervision of a Journeyman Distribution Operator. As reflected in the attached declaration from NDCC Operator #2 (Ex. EEE), he did not have authority to cut power. He thought the loss of power might be due to the open fuse described by the Troubleman. NDCC Operator #2 does not recall discussing with his supervisor the cause of the outage or the possibility of cutting power.[11] In a recorded phone call (Ex. JJ-11, Dkt. 1474-12), NDCC Operator #2 advised the Dixie Troubleman to return to Fuse 17733 to address the outage. The Dixie Troubleman thought that the power outage was due to one or more fuses opening; the dam had switched to backup generation and power appeared to be off at the tunnel, and there did not appear to be a risk of single phasing damaging customer equipment. The Dixie Troubleman therefore went to check the fuses. *See* Ex. EEE (NDCC Operator #2 Decl.) ¶¶ 4-5; *see also* Ex. DDD (Dixie Troubleman Decl.) ¶ 6.

Question 39:

On the Bucks Creek Circuit, where were any fuses other than at Pole 17733 and at the Cresta Dam? If so, did any of them blow on July 13 (and if so when)?

PG&E Response:

The only fuses located on the Bucks Creek 1101 Line, other than those located at

[11] NDCC Operator #2's supervisor, NDCC Operator #3, is currently out ill. PG&E will advise the Court if the supervisor recalls being aware of or consulted about the outage.

Fuse 17733 and those located at Fuse 805 at Cresta Dam, are those located at Fuse 7141. Fuse 7141 is located on a trunk line near the beginning of the Circuit that provides electricity to a three-phase transformer that serves PG&E's Bucks Creek Powerhouse (part of PG&E's hydro-generation facilities).

PG&E has seen no evidence that any of the fuses at Fuse 7141 operated on July 13, and the available evidence is to the contrary. Fuse 7141 is located upstream of the transformer on the trunk line, and operation of its fuses would have interrupted the flow of power from the Bucks Creek 1101 substation to the Bucks Creek Powerhouse. But the Rock Creek Switching Center Operator's Log for July 13-14 (Ex. E-1, Dkt. 1408-6) indicates that on July 13 power continued to flow without interruption from the Bucks Creek 1101 Line to the Bucks Creek Powerhouse. In particular, one entry indicates that at 9:04 a.m. on July 13, the same roving operator who had previously reported the loss of power at Cresta Dam and the tunnel now reported that the Bucks Creek 1101 Line was continuing to provide power to the Bucks Creek Powerhouse (*see id*. at p. 2 of 10). Another entry at 12:04 p.m. *on July 14* indicates that the Bucks Creek Unit 1 hydro-generation unit was switched for the first time to a mode of operation whereby it uses its own hydro-generated electricity to power itself, rather than electricity drawn from the distribution line (*see id*. at p. 8 of 10). And a third entry indicates that it was not until 8:00 p.m. on July 14 that the Rock Creek Switching Center for the first time received a SCADA alarm indicating a loss of distribution line power to the Bucks Creek Powerhouse (*see id.* at p. 10 of 10). It is at 8:00 p.m. on July 14 that PG&E's records indicate that the line recloser was opened and the entire Bucks Creek 1101 Line was de-energized.

Question 40:

On July 13, did PG&E have in place any protocol or procedure for monitoring or examining, in real time, data from the SCADA system/recloser from the Bucks Creek substation to assess for ground faults?

PG&E Response:

Yes.

a. PG&E's RT SCADA system reports ground faults in real time if and when a device operates as a result of such a fault, such as when a recloser opens because it has detected a ground fault. The RT SCADA system also reports when the ground current exceeds the Minimum to Trip ("MTT") level, but not long enough to open the recloser; however, the SCADA message in that instance does not advise what type of fault (ground or phase) is detected. Here, the recloser did not detect a ground fault and it did not open, so no ground fault was recorded or reported by the SCADA system.

On July 13, 2021, the line recloser at the Bucks Creek substation for the Bucks Creek 1101 Line was set to open and de-energize the line if the calculated ground current exceeded either of two ground fault conditions: First, the line recloser would open and de-energize the line if it detected a ground fault with current of 50 amps or more that lasted for a pre-set length of time determined by the selected time characteristic curve ("TCC").[12] Second, the line recloser would open and de-energize the line if it detected a ground fault that continuously remained at 20 amps or more for a period of 20 seconds. *See* Ex. B, Recloser Witness 1 Decl. (Dkt. 1408-2) at 2:25-3:12; Ex. D, Recloser Witness 3 Decl. (Dkt. 1408-4) ¶¶ 4-10.

If either of those events had occurred (which they did not), the line recloser would have sent an alarm to the RT SCADA system indicating that the line recloser had operated and which of the two pre-set ground fault conditions had triggered that operation.

b. If a fault is not sufficient (in amplitude and/or duration) to operate a SCADA enabled device, a Distribution Operator can attempt to assess potential for a ground fault by comparing the ground current and the loads on each phase in real time with historical experience, as described below. A Distribution Operator may attempt this under various circumstances, such as when analyzing a SCADA alarm that the current had exceeded the MTT, or when an outage is reported (among others). Generally, a high-impedance ground fault is difficult to identify using

[12] Under the applicable TCC, the greater the current in excess of the MTT of 50 amps, the shorter the period of time required before the recloser would open and de-energize the line.

current levels, as discussed further in response to Question 47, below, concerning industry and PG&E efforts to develop reliable technologies and processes for detecting high-impedance ground faults.

Throughout the day of July 13, 2021, the controller unit in the line recloser at the Bucks Creek substation for the Bucks Creek 1101 Line calculated a potential ground current based upon the manufacturer's algorithms and the actual measurements of the current flowing on each of the three phases. Some level of potential ground current is consistent with normal operation of the line, and the level may vary based on circumstances particular to the line. This ground current data was reported through PG&E's RT SCADA system, and was recorded in PG&E's PI Historian database. PG&E previously provided to the Court the potential ground current levels for the Bucks Creek 1101 Line recorded in the PI Historian database for July 13, 2021. *See* Ex. PP (Dkt. 1479-5).

A large anomaly in the potential current going to ground and/or in the phase loads can be indicative of a ground fault. When Distribution Operators are reviewing for such anomalies on a line, they can utilize PI Historian to view the historical ground current and phase loads on a line and compare that historical data to the present ground current and phase loads.

Here, a SCADA alarm that current had exceeded the MTT occurred at 6:48 a.m.[13] and was followed shortly thereafter by notice from the Rock Creek Switching Center that Cresta Dam lost AC power. NDCC Operator #1 does not now recall the SCADA alarm but does recall receiving notice that the dam had lost power. Following the initial notice of the outage at Cresta Dam, and at multiple other times during his shift, NDCC Operator #1 checked both the phase loads and the ground current in real time and compared those to historical data.[14] NDCC Operator #1 did not see any anomaly indicative of a ground fault.

---

[13] This SCADA alarm was triggered by the phase-to-phase fault reflected in the oscillography recorded at that time. But, as noted above, this type of SCADA alarm does not advise the Distribution Operator why type of fault (phase or ground) triggered the alarm. It was immediately followed by a SCADA alarm that the current had returned to normal (that is, below the MTT).

[14] *See* Ex. JJ-2, Dkt. 1474-3 (NDCC Operator #1 tells Hydro Operator #1 in a call that started at 9:07 a.m. on July 13, 2021 that "everything looked normal on the breaker").

Question 41:

On July 13, did PG&E have anywhere in its California system any protocol or procedure for monitoring data from the SCADA system to detect ground faults in real time? If so, please describe it.

PG&E Response:

Yes. As noted in response to Question 40, the SCADA system monitors for device operations in real time and sends an alarm indicating a ground fault when a SCADA-enabled device in PG&E's distribution system operates due to such a fault, such as when a recloser opens.[15] In addition, if an exceeds-MTT SCADA alarm is received or an outage is reported (among other circumstances), a Distribution Operator may attempt to assess the potential for a ground fault by comparing current going to ground and the phase loads in real time with historical experience, as described in response to Question 40. As noted in response to Question 47, it is widely recognized in the industry that it is difficult to detect high-impedance ground faults based on load data because "low fault currents are often masked by load conditions."[16]

As part of its ongoing efforts to evaluate new protection technologies, a PG&E pilot program has implemented downed conductor detection ("DCD") feature to hundreds of line-recloser

[15] As part of its ongoing efforts to evaluate emerging protection technologies, PG&E has installed a Rapid Earth Fault Current Limiter device on one distribution substation as described in PG&E's 2021 Revised Wildfire Mitigation Plan at pages 352-54, 397, and 621-22. *See* PG&E's Response to Question 47 below. If this device operates, it too will send a SCADA alarm indicating a ground fault in real time.

[16] Ex. QQQ-1, M. Kistler, F. Heleniak & T. Varshney, "Practical Experience With High-Impedance Fault Detection in Distribution Systems," ("Kistler Presentation") at 1, originally presented at 46th Annual Western Protective Relay Conference (rev. ed. 2019) ("High-impedance faults (HIFs) on distribution systems, such as those caused by downed conductors, continue to be difficult to detect using traditional protective relaying because low fault currents are often masked by load conditions."); *see also* Ex. QQQ-2, S. Hayes, D. Hou & N. Fischer, "Understanding Ground Fault Detection Sensitivity and Ways to Mitigate Safety Hazards in Power Distribution Systems," at 4, presented at 57th Annual Minnesota Power Systems Conference (2021) ("Hayes Presentation") ("For high-impedance faults resulting from downed conductors that do produce some fault current, . . . the fault current can still be less than the system load unbalances and the traditional ground overcurrent protection cannot differentiate downed conductor faults from single-phase loads.").

controllers in its distribution system.[17] This software does not attempt to identify a ground fault by looking at ground current levels; rather, DCD software attempts to detect (or, more precisely, to *infer*) the presence of a high-impedance ground fault in real time if certain characteristics are detected in the oscillography that the controller vendor has concluded are associated with such a fault. While the reclosers in this pilot program are not set to operate upon the detection of a ground fault by the DCD software, they will send a SCADA alarm indicating the DCD software has detected a ground fault.

Question 42:

On July 13, which PG&E employee or contractor were aware that the amps on Phase C had dropped to a steady state of one amp on the Bucks Creek Circuit? (Interview them and advise. Don't limit your answer to "documents.") Did any PG&E employee or contractor see anything in the data or information known about the outage that could indicate ground faults? If so, what? What follow-up did they pursue?

PG&E Response:

It is standard practice that Distribution Operators monitor PG&E's RT SCADA system for the specific distribution lines within the division(s) for which they have responsibility during their shifts, which can include hundreds of circuits. On July 13, from the time of the 6:48 a.m. fault event through the opening of the third fuse at Fuse 17733 by the Dixie Troubleman and his observation of the tree on the line, the only Distribution Operators whose responsibilities included monitoring the Bucks Creek 1101 Line were NDCC Operator #1, NDCC Operator #2, and NDCC Operator #3. There was also one floor lead working on July 13 ("NDCC Floor Lead #1") supervising all the Distribution Operators in the NDCC that day. With one exception,[18] PG&E interviewed each of these individuals.

---

[17] *See* PG&E's 2021 Revised Wildfire Mitigation Plan, at 397 (row C.7 in table).

[18] NDCC Operator #3, a journeyman who came on shift after NDCC Operator #1 and supervised NDCC Operator #2, was unavailable for an interview before the submission deadline and is currently out ill. PG&E will interview NDCC Operator #3 as soon as possible and will advise the Court if the operator was aware of the amps on Phase C on the Bucks Creek 1101 Line on July 13, or saw any data or was aware of any information indicating a ground fault.

NDCC Operator #1 recalls looking at both the real time phase load and ground current data for the Bucks Creek 1101 Line on multiple occasions during his shift on July 13 after learning of the outage at Cresta Dam. NDCC Operator #1 does not recall specific information about the amperage on any particular phase. NDCC Operator #1 does recall comparing the real time data to historical data from the same circuit. Based on these comparisons of real time and historical data, NDCC Operator #1 did not see any indications that a ground fault had occurred. The data, previously provided to the Court, does not indicate a ground fault on Phase C, including for the reasons explained in PG&E's Response to Questions 12 (Dkt. 1479) and 36 (third subpart) and 50 herein. NDCC Operator #1 recalls advising NDCC Operator #2 at shift change regarding the information he had related to the outage.

Neither NDCC Operator #2, who was involved in responding to the power outage after the time of the 6:48 a.m. fault event through the opening of the third fuse at Fuse 17733 by the Dixie Troubleman and his observation of the tree on the line, nor NDCC Floor Lead #1 was aware of the amps on Phase C on the Bucks Creek 1101 Line on July 13 or saw any data or was aware of any information indicating a ground fault. As noted in response to prior questions, PG&E has interviewed various NDCC operators and others who responded to the outage and has not identified any other PG&E employee or contractor who was aware of the amps on Phase C on the Bucks Creek 1101 Line on July 13 or who, prior to learning of a tree leaning on the line after the Dixie Troubleman arrived at the location, saw any data or was aware of any information indicating a ground fault.

Question 43:

List all PG&E employees or contractors who had access on July 13 to the amperage data on the Buck Creek 1101 line and state their titles and location of work. With respect to each, state what steps each would have had to do to view the data.

PG&E Response:

Any Distribution Operator[19] responsible for operating the electric distribution system on July 13 would have had access via the RT SCADA system to real time load data for PG&E's distribution circuits—including the Bucks Creek 1101 Line, though, typically, Distribution Operators monitor PG&E's RT SCADA system for the specific distribution lines within the division(s) for which they have responsibility during their shifts. Distribution Operators access SCADA data through the RT SCADA system on PG&E's Operational Data Network ("ODN").

Distribution Operators would also have access to historical load data available in PG&E's PI Historian database for all distribution lines, including the Bucks Creek 1101 Line. Distribution Operators access this data through the PI Historian system on PG&E's Utility Data Network ("UDN").

Thus, Distribution Operators at other facilities would have had the ability to access current and historical data on the Bucks Creek Line, but their jobs did not require it and PG&E has no reason to expect that they would have done so. PG&E's SCADA and Automation Specialist teams have access to the RT SCADA system for purposes of supporting the RT SCADA system. Other PG&E employees have "view only" access to the RT SCADA system. Many PG&E employees would have access to historical load data in the PI Historian database.

A list of the 74 Distribution Operators, Apprentice Distribution Operators, and Lead System Operators on shift in the North, Central, or South Distribution Control Centers ("DCCs") between 6:00 a.m. and 6:00 p.m. on July 13, 2021 is attached as Exhibit FFF. PG&E estimates that another several hundred individuals had "view only" access to RT SCADA data for the Bucks Creek 1101 Line at that time and an even larger group had access to historical load data through the PI

[19] Distribution Operators include System Operators as well as Lead System Operators ("LSOs"). LSOs operate primarily in one of two roles: as "Processing LSOs" responsible for planning and scheduling future work, or as "floor leads" that supervise and manage System Operators. While only floor leads would normally monitor live data in RT SCADA, the provided list includes all LSOs. Supervisors in Distribution Control Centers typically do not have SCADA access at their workstations.

Historian database. PG&E can, upon request, compile and provide the Court with a list of other personnel who had the ability to access the data on these systems.

Question 44:

On July 13, at the time of the phase-to-phase fault, did any SCADA alarm sound? Was there an "alarm printout?" as referenced in TD-2700P-09 (Dkt. No. 1479, Exh. LL-3 at 5, at §2.4)? If so, did the alarm allow for "prioritizing or categorizing alarms on the alarm printout" (id. at 4)?

PG&E Response:

When the line recloser for the Bucks Creek 1101 Line recorded momentary current levels in excess of the Minimum To Trip ("MTT") at approximately 6:48 a.m. on July 13, an alarm to this effect appeared in the SCADA system. The audible alert associated with this alarm is described as "Tone (alert23.wav)" in TD-2700P-09 Attachment 2, Integrated SCADA Alarm Summary Table. There was no hard copy "printout," but the SCADA alarm was saved in the system and had a priority level of P04.[20] As set forth in TD-2700P-09 and Attachment 2 thereto, SCADA alarms have assigned priority levels ranging from Priority 1 (lowest) to Priority 10 (most critical). The alarms are categorized and described in TD-2700P-09, in section 2, pp. 3-5, and Attachment 2 thereto. (*See* Dkt. 1479-1, Ex. LL-3; Dkt. 1502-14, Ex. CCC-1.) NDCC Operator #1 arranges his screens such that one screen contains all SCADA alarms with priority level 2 and above, while a second screen contains *only* the higher priority alarms (priority level 6 and above). For the 6:48 a.m. SCADA alarm for momentary current in excess of the MTT with a priority level of P04, the priority guidance recommends monitoring the situation and, if needed, dispatching personnel, both of which are actions NDCC Operator #1 took.

---

[20] Priority 4 alarms are categorized as "Critical: This level is comprised of all security alarms, other significant substation trouble indicators, communication, and field device alarms." Dkt. 1479-1, Ex. LL-3 at p. 4 of 13. Operators are instructed to "Take action as needed. Analysis is required." *Id.* "The decision to dispatch personnel or only monitor the situation is based on the known concurrent activity and circumstances. In some instances, close monitoring may be enough; in others, dispatching personnel may be required." *Id.* at p. 5. As noted in other responses, separate from the SCADA system, the operator received notification that the power was out at the dam and the tunnel, and the operator dispatched personnel and monitored the situation. *See, e.g.*, Dkt. 1408 at 3-4.

Question 45:

At that time, was there a "change in circuit breaker, line recloser, or switch positions with wav. File alerts," as referenced in TD-2700P-09 (Dkt. No. 1479, Exh. LL-3 at 4)?

PG&E Response:

PG&E understands that a change in circuit breaker, line recloser or switch position would be an opening or closing of such a device, as set forth in TD-2700P-09. (*See* Dkt. 1479-1, Ex. LL-3 at 4; Dkt. 1502-14, Ex. CCC-1 at 1-2.) There was no "change in circuit breaker, line recloser, or switch positions with wav. file alerts" when the line recloser for the Bucks Creek 1101 Line recorded momentary current levels in excess of the MTT at approximately 6:48 a.m. on July 13. As set forth in PG&E's response to the Court's July 21, 2021 order (Dkt. 1408), the duration of the current in excess of the MTT did not meet the requirements to open the line recloser for the Bucks Creek 1101 Line.

Question 46:

Did the July 13 phase-to-phase fault, which registered at the recloser (see Dkt. No. 1408 at 2) and was recorded in SCADA, involve or qualify as a "change in circuit breaker, line recloser, or switch positions" (ibid.)?

PG&E Response:

No. PG&E refers the Court to the prior answer.

Question 47:

On July 13, did the industry have any technology for detecting ground faults on a line in real time? If so, please describe. Does PG&E utilize such technology anywhere?

PG&E Response:

Protective devices widely used by electric utilities on their distribution lines include fuses, line reclosers and breakers. Fuses will operate in real time in accordance with their time characteristic curve ("TCC") whether the necessary current results from a ground fault or from some other cause. Line reclosers and breakers typically have microprocessor or mechanical elements that measure in real time the ground fault current referred to as "Igrd" and operate when that current exceeds minimum to trip ("MTT") thresholds that depend upon the selected settings. PG&E makes extensive use of these technologies, including on the Bucks Creek 1101 Line, which has fuses and a line recloser.

High impedance ground faults present special challenges to these standard protection technologies. Because the fault current is so low, it is difficult to distinguish the ground fault current from the ground current occurring during normal operations due to imbalanced load. Development of a sensitive ground fault ("SGF") element for reclosers and breakers—which operates in real time after the MTT is exceeded for a fixed period of time (rather than based on a TCC)—is one response to the high impedance ground fault problem. Because the SGF element will not operate simply because of a brief surge in ground current, it is possible to set the MTT for that element at a lower level without leading to an unacceptably high rate of service outages based on transient ground fault conditions. PG&E uses the SGF element on many of its reclosers protecting 12kV distribution feeders, including the Bucks Creek 1101 Line.

SGF elements mitigate, but do not eliminate, the high impedance ground fault challenge because such faults can and do occur at amperage levels below those reasonably used in SGF elements. As a result, the industry and PG&E are evaluating the effectiveness and practicality of various new and emerging technologies that use methods other than the measurement of ground current to detect (or more precisely, to *infer*) the presence of a high impedance ground fault.[21]

DCD software is one such technology that PG&E is using in a pilot program as described in the Response to Question 41 above. Another such detection technology is part of the Rapid Earth Fault Current Limiter system that PG&E has installed on one distribution substation as a pilot program.[22] This detection technology looks for increases in neutral voltage at the substation,

---

[21] For recent summaries and discussions of the challenges posed by high impedance ground faults, and the current state of technology and research in this area, *see* Ex. QQQ-2, Hayes Presentation; Ex. QQQ-3, D.P.S. Gomes & C. Ozansoy, "High-impedance faults in power distribution systems: A narrative of the field's developments," 118 ISA Transaction (2021); Ex. QQQ-1, Kistler Presentation.

[22] *See* PG&E's 2021 Revised Wildfire Mitigation Plan, at 352-54, 397, and 621-22.

rather than increases in ground current, as an indicator that a single phase-to-ground fault has occurred, and upon detection a device operates that very quickly chokes off the ground current to the affected phase to an extremely low level. Among other technical challenges, PG&E's initial pilot results indicate that there are difficulties integrating the technology with PG&E distribution systems even after PG&E created special equipment known as Capacitation Balancing Units to balance the circuit's capacitance.[23]

Question 48:

Normally, all three phases would have supplied power to the Cresta Dam and tunnel. If only one phase went out (as in its fuse had blown), would the other two phases normally have continued to supply power? If two phases, however, went out, would the one phase power the dam or tunnel alone? If you answered "yes" to the first question and "no" to the second question, didn't the fact that no power was being received at the dam and tunnel on July 13 mean that at least two phases were out?

PG&E Response:

If one phase lost power at Cresta Dam, that facility would automatically switch to its onsite backup generator to continue powering operations. Likewise if two or three phases lost power. The fact that distribution line power was off at Cresta Dam, and the facility was instead drawing from its back-up generation system, did not indicate whether one, two or all three phases had been de-energized.

The meter for the tunnel facility is based on only one phase; thus, the fact that the meter appeared to be out does not indicate whether power was lost on one, two, or three phases. Except in rare instances where coordination with a customer is required to assure integrity of the distribution system (e.g., a co-generation facility), PG&E does not inquire what specific equipment in what configuration is present at a customer facility. The tunnel is not a facility falling within the

[23] PG&E also is piloting two new and emerging sensor technologies—Radio Frequency ("RF") Network Monitoring sensor technology and Event Classification through Current and Voltage Monitoring ("ECCVM") sensor technology—in an effort to identify and locate incipient conditions that could become distribution network fault events. See PG&E's 2021 Revised Wildfire Mitigation Plan ("WMP") at pages 492-93. At present, this technology combination is not being used for real time monitoring in the pilot program. ECCVM includes ground fault detection algorithms.

very limited exception. PG&E therefore is not certain what equipment is operated at the tunnel or what the impact would be of various phase outage combinations on the continued operation of that equipment.

On July 13, determining precisely why power had been lost at the tunnel (as at the dam) required an examination, which the Dixie Troubleman was carrying out.

Question 49:

Was there a way at the Cresta Dam for the Troubleman to test each incoming phase (for example, against ground) to see whether it was a live wire at the dam? Did he do this?

PG&E Response:

There are methods that a troubleman can use to attempt to determine whether a power line is energized, such as using a high voltage detector or amp meter or amp stick. Such a tool can be used to determine whether a power line is energized (high voltage detector), or to measure current (amp meter or amp stick). As indicated in the Dixie Troubleman's attached declaration, he did not use such a method at the Cresta Dam because, (a) based on the conditions he observed and his experience with a prior outage, he did not believe the equipment at the dam and tunnel were at risk due to single-phasing, if single-phasing were present, and (b) he could see based on visual inspection where the problem appeared to be, i.e., at Fuse 17733.

Question 50:

State whether (or not) the following would account for the amperage data patterns described in Dkt. No. 1494, questions 24–27: Cresta Dam and Tunnel used all three phases and the railroad used only A and B, so Phases A and B normally drew more amps. When Phases A and B then blew their fuses at Pole 17733, this left the railroad as the only customer drawing power on A and B, so the currents on A and B were correspondingly reduced. Phase C, by itself, could not alone deliver power to the dam and tunnel (since at least two phases had to be connected to any load). However, instead of showing zero amps, Phase C was showing a steady 1.1 amps. This 1.1 amps was due to a ground fault on Phase C.

PG&E Response:

No; for several reasons, the stated conditions do not account for the amperage data patterns found in the July 13, 2021 load data for the Bucks Creek 1101 Line recorded in PG&E's Process Information ("PI") Historian database.

a. The transformers serving the railroad appear to have connected to a different combination of two phases at each of the three railroad locations; therefore, the railroad could draw power from Phases A, B and C (not just from Phases A and B).[24]

b. Even after the fuses operated at Fuse 17733, power could be drawn on all three phases (A, B and C) *upstream* of the fuses—not only by the railroad, but also by the three-phase transformer serving the Bucks Creek Powerhouse (part of PG&E's hydro-generation facilities) located on a trunk line near the Bucks Creek substation.

c. The steady 1.1 amp recorded draw on Phase C remained even after the Troubleman operated the third fuse at approximately 5:00 p.m. on July 13. At that point, no current through Phase C (or any other phase) could have been reaching the tree on the line. The steady 1.1 amp recorded draw on Phase C also remained after Switch 941 was opened at Cal Fire's request at approximately 8:30 p.m. on July 13, at which point no location downstream of Switch 941 could have received current through Phase C (or any other phase). Current continuing to flow after the opening of the fuse and the operation of Switch 941 could not be the ground fault here at issue.

[24] In its November 1, 2021 submission, PG&E reported that this is the case assuming the employee who conducted a helicopter inspection of the line on October 29 correctly reported both the location of the connections between the conductors and the transformer at each of the three railroad facilities, and correctly identified all of the transpositions of the conductors between these three transformer locations. *See* PG&E's Response to Question 33 (Dkt. 1502). Since that time PG&E has continued to analyze the available data, as it indicated it would do. Based on that additional work, PG&E believes that the available data continues to support the conclusion that each of the three railroad sites was served by a different combination of phases. PG&E further believes that the available data indicates the railroad site located closest to the Bucks Creek substation was served by phases A and C, the next railroad site downstream from the substation was served by phases A and B, and the railroad site furthest from the substation (and the one that is load-side of Switch 941) was served by phases B and C.

d. It was not until 12:04 p.m. on July 14—following a brief increase in load on all three phases—that the recorded current dropped to "0" on Phase C (as well as on the other two phases).[25] The Rock Creek Control Center Operator's Log indicates that (1) the Control Center planned, at noon on July 14, to switch the Bucks Creek Unit 1 hydro-generation unit to a mode of operation whereby it uses its own hydro-generated electricity to power itself, rather than electricity drawn from the distribution line, and (2) that task was completed at 12:04 p.m. on July 14 (*see* Ex. E-1, Dkt. 1408-6 at p. 8 of 10). In other words, a recorded 1.1 amp load on Phase C remained until the Bucks Creek Unit 1—near the beginning of the line, and nowhere near the fallen tree—ceased drawing power. This information indicated that the power flowing through Phase C after the opening of Switch 941 reflected draw by the Bucks Creek Powerhouse, not a ground fault.

e. Based on the phase map PG&E has been preparing using the best available information, and the Troubleman's identification of the location on the cross arm of the fuse he had to manually open, PG&E believes that the fuse that remained closed at Fuse 17733 prior to approximately 5:00 p.m. on July 13 was on Phase A. The fuses that were already open were on Phases B and C. This is consistent with the oscillography which, as previously described to the Court (*see* PG&E's Response to Question 29, Dkt. 1497), indicates a phase-to-phase fault between Phases B and C; thus, if two fuses opened when the phase-to-phase fault occurred at 6:48 a.m. (as the Court's question reasonably assumes, and as can be determined from the fuses in Cal Fire's possession), the two fuses that operated were on Phases B and C. If, as it appears, the fuses that opened were on Phases B and C, then the current on Phase C detected at the recloser could not have been flowing downstream on Phase C past Fuse 17733 to a ground fault. In these circumstances, if current was reaching the tree and going to ground, that current was flowing from the substation *down Phase A* though the closed fuse at Fuse 17733. How that current made its way to or through the tree cannot be determined from the recloser data.

[25] *See, e.g.*, Attach. 1 to Dkt. 1497. As previously noted, the RT SCADA system reports any current below 0.5 amps as zero amps (*see* Dkt. 1497).

Question 51:

If the overall risk ranking was 568 out of 3,074 in the Enhanced Vegetation Management Tree Weighted Prioritization List for 2021, why does PGE-DIXIE-NDCAL-000017019 (at 3) appear to describe the "2021 Risk Rank" simply as "11" (Dkt. Nos. 1428 at 9; 1472)?

PG&E Response:

The "2021 Risk Rank" identified in PGE-DIXIE-NDCAL-000017019, a draft agenda for the April 14-16, 2021 site visit with several stakeholders to discuss system hardening on the Bucks Creek 1101 Circuit and others like it, describes the 2021 Equipment Risk Model ranking, which is a different ranking than the Enhanced Vegetation Management Tree Weighted Prioritization List for 2021 (referenced in the Court's question). The risk ranking that is key to system hardening prioritization is the 2021 Equipment Risk Model. The risk ranking for the Bucks Creek 1101 CB Circuit Protection Zone ("CPZ")—one of the CPZs involved in the site visit—under the 2021 Equipment Risk model is 11. PG&E supplied the Equipment Risk Model ranking to the party that composed the agenda because that was the risk ranking that PG&E understood that party wanted to include and, given the focus on system hardening, was most relevant to the site visit that day.

As noted in PG&E's August 16, 2021 response (Dkt. 1416), the rankings for Enhanced Vegetation Management are calculated based on different factors.

Question 52:

What does "H tag remediation of jobs put on hold . . . Targeted for 12/31/20" mean (Dkt. No. 1472, PGE-DIXIE-NDCAL-000017031 at 1)? What jobs were put on hold and why? Were they related to "the presence of an older and smaller gauge conductor, the presence of splices from prior conductor repairs" (Dkt. No. 1428 at 10)? When was the work completed? Please include a sworn response by the individual named in line nine of document PGE-DIXIE-NDCAL-000017031, and any other knowledgeable individuals.

PG&E Response:

H tags are moderate and low priority tags (Priority E and F tags, respectively) identified as tags that can be executed through system hardening and other projects. The document referenced above (PGE-DIXIE-NDCAL-000017031) is an agenda for a Grid Design team check-in meeting following the re-prioritization of system hardening work that resulted from adoption of the 2021 Wildfire Distribution Risk Model. That re-prioritization caused the company to consider certain system hardening projects and put others on hold. The referenced line item concerns a request to look into the number of H tags associated with projects that had been placed on hold following the re-prioritization. *See* Exs. GGG, HHH, and III.

The Bucks Creek 1101 Line was not one of the jobs put on hold as referenced in this December 3, 20202 meeting agenda. Indeed, the Bucks Creek 1101 Line was not approved for system hardening until January 2021. Therefore, none of the H Tags referenced in the agenda are associated with the Bucks Creek 1101 Circuit.

After the Bucks Creek 1101 Circuit was approved for system hardening, certain E and F tags along the line were converted or identified for conversion to H tags. None relates to the presence of an older and smaller gauge conductor or, the presence of splices from prior conductor repair.[26]

Question 53:

Were any drones in the area of Bucks Creek 1101 line between 7 am and 5 pm on July 13 that could have been used to inspect the line in lieu of the Troubleman waiting to reach the fuses?

PG&E Response:

As explained in PG&E's prior responses (Dkts. 1416, 1428), PG&E records reflect that two PG&E contractors operated drones in the morning on July 13, 2021 in Butte County in connection with inspections of PG&E transmission equipment. Those contractors took images of PG&E structures on transmission lines as part of PG&E's enhanced inspection process; one structure

[26] Subsequent to the referenced document, PG&E's records reflect that approximately 25 E and F tags on the Bucks Creek 1101 Circuit were converted or identified for conversion to H tags in May 2021: 22 were for poles, 1 was for a cross arm, and 2 were for trimming vegetation around the base of poles and guy wires.

was approximately 20 miles from Fuse 17733, and the other was approximately 30 miles from Fuse 17733.

PG&E UAS (Unmanned Aerial Systems) Operations, PG&E's internal drone team, was in Concord for training. In late 2019, PG&E initiated a pilot program with the IBEW to train certain linemen and other employees in the use of small drones in their work. None called into dispatch for flight clearance on July 13; none are based in Butte or Plumas Counties; and none of the records and GPS data that PG&E has reviewed indicate that any were in Butte or Plumas Counties between 7:00 a.m. and 5:00 p.m. on July 13.

Question 54:

> *According to Cal FIRE, the CPUC, and PG&E, "Inspectors should not confuse tree health and tree stability. High-risk trees can appear healthy in that they can have a dense, green canopy," but "tree decline due to certain types of root disease is likely to cause the tree to be structurally unstable." California Power Line Fire Prevention Field Guide, 2021-power-line-fire-prevention-field-guide-ada-final_jf_20210125.pdf, at 49. Did PG&E's inspectors examine the Douglas Fir that fell on the Bucks Creek 1101 line for root disease during the routine inspection in November 2020? In the CEMA patrol on January 14, 2021 (Dkt. No. 1416 at 9)? What specifically did the inspector(s) do to inspect for root disease? Append all records and photographs, interview all witnesses, and provide those witness' statements.*

PG&E Response:

Per the Court's order, PG&E has interviewed the contractors who inspected the portion of the Bucks Creek 1101 Line that included the Douglas Fir that fell on the line in the November/December 2020 routine ground inspection and the January 2021 aerial CEMA inspection. Their declarations are attached. *See* Exs. JJJ, KKK, LLL and MMM.

The language quoted by the Court from the Power Line Fire Prevention Field Guide is itself a verbatim quote from the Utility Tree Risk Assessment, Best Management Practices for Assessing the Risk of Tree Strikes to Electric Distribution and Transmission Lines and Related Equipment (2020), published by the International Society of Arboriculture ("ISA Utility Tree Risk

Manual"), at 32; *see also* ISA Tree Risk Assessment, Second Edition (2017), at 31 (containing same language).

In accordance with the ISA Utility Tree Risk Manual, the inspectors conducted a "Level 1" or "Limited Visual" assessment, which is "the most common, practical, and recognized assessment used by utilities." ISA Utility Tree Risk Assessment, at 13, 22.[27] When the results of a Level 1 inspection suggest a closer inspection of an individual tree is required, they conduct or call for a Level 2, "Basic Assessment," which requires a 360 degree inspection of the tree.

As the ISA manual notes, root problems are hard to assess. *Id.* at 74 ("Root problems can be very difficult to detect during Limited Visual [Level 1] and Basic [Level 2] assessments."). Accordingly, the inspectors look for the symptoms and potential indicators of root problems identified in the manual. "Symptoms [of root problems] to look for include the following": "a cavity in the root collar, a canker that extends to the soil line, or a visibly pruned or broken root stub," *id*.; "fungal fruiting structures attached to roots or the root collar," *id*.; "dead or detached bark," *id.*; "abnormal root flares or fused buttress roots," *id*.; "buried root collar," *id*.; "decay in the base of the tree," *id*. at 75; and "lower tree trunks and buttress roots that exhibit oozing," *id*.

In addition, "tree and site conditions that can indicate the potential for root-related structural problems" include: "crown dieback, thinning, or decline," *id*.; "soil disturbance," *id.*; "soil mounding or cracking," *id.* at 76, "excessive soil moisture," *id*.; and "soil erosion," *id.*

As described in their declarations, the inspectors who reviewed the span in question do not recall the Douglas Fir in question, but they inspected trees like the Douglas Fir within striking distance of the line and looked for these various symptoms that might indicate root disease.

[27] Limited visual assessments are "the primary method used when assessing risks in large populations of trees." *Id.* at 14. "When conducted by trained professionals, Limited Visual assessments can provide utility vegetation managers with an adequate level of information that can accomplish their risk-management goals." *Id.*

Exhibit NNN contains records from the 2020 routine inspection.[28] Exhibit OOO contains photographs provided by inspectors from the 2020 routine inspection.

Exhibit PPP contains records from the January 2021 CEMA inspection. PG&E has not located any photographs from the January 2021 CEMA inspection.

Dated: November 16, 2021

Respectfully Submitted,

JENNER & BLOCK LLP

By: /s/ Reid J. Schar
Reid J. Schar (*pro hac vice*)

CRAVATH, SWAINE & MOORE LLP

By: /s/ Kevin J. Orsini
Kevin J. Orsini (*pro hac vice*)

CLARENCE DYER & COHEN LLP

By: /s/ Kate Dyer
Kate Dyer (Bar No. 171891)

Attorneys for Defendant PACIFIC GAS AND ELECTRIC COMPANY

[28] The routine inspection of Bucks Creek 1101 began in November 2020 and was completed in December 2020. In July 2020, contractors inspected a line in Pulga, CA that, for historical reasons, PG&E's vegetation management database associated with Bucks Creek 1101. The circuit in Pulga is not connected electrically to Bucks Creek 1101, which was shortened after the Camp Fire.