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**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

**PACIFIC GAS AND ELECTRIC
COMPANY'S RESPONSE TO
REQUEST FOR INFORMATION**

Judge: Hon. William Alsup

Date: July 31, 2019

1 Defendant Pacific Gas and Electric Company (“PG&E”) respectfully submits this
2 memorandum in response to the Court’s July 10, 2019 Request for Offender PG&E to Supply
3 Information. As required by the Request, PG&E hereby responds to each paragraph of a *Wall Street*
4 *Journal* article dated July 10, 2019, bearing the headline “PG&E Knew for Years Its Lines Could
5 Spark Wildfires, and Didn’t Fix Them” (the “WSJ Article”).

6 PG&E has acknowledged that its transmission equipment caused the devastating November 8,
7 2018 Camp Fire that killed 85 people, destroyed the Town of Paradise, and burned over 150,000 acres.
8 And PG&E understands the magnitude of the challenges it faces in reducing wildfire risk and the
9 responsibility it owes all Californians to address those risks. The October 2017 wildfires and the
10 Camp Fire have demonstrated the new normal of significantly increased wildfire risk. PG&E
11 understands that it must do more than ever before to address this new risk profile. PG&E welcomes
12 input from the community to the ongoing dialogue on how PG&E can operate its electric system more
13 safely at this time of unprecedented fire risk.

14 In preparing this submission, PG&E has investigated the factual basis for each statement in the
15 WSJ Article. While it has not been possible to provide exhaustive responses here given the page limit
16 for this submission, PG&E hopes that these responses will contribute to an accurate and more
17 complete understanding of the issues, including PG&E’s maintenance of its transmission lines in the
18 years before the Camp Fire and its efforts to develop enhanced, risk-based methods for inspecting and
19 maintaining its thousands of transmission line miles.

20 PG&E takes this opportunity at the outset to address briefly three issues raised by the *WSJ*
21 Article. *First*, since the Camp Fire, PG&E has fundamentally changed its approach in light of the new
22 increased risk environment by, among other things, comprehensively inspecting its transmission,
23 distribution and substation assets in elevated and extreme fire-threat areas before the 2019 fire season.
24 As PG&E reported on June 19, 2019, by that time, PG&E had addressed every highest-priority
25 condition on transmission structures and at substations, and 97% of all such conditions on distribution
26 poles. PG&E continues to take corrective actions to address remaining conditions. These enhanced
27 inspections are but one element of PG&E’s redesigned Community Wildfire Safety Program, first
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1 implemented in response to the October 2017 wildfires. That program also includes real-time, round-
2 the-clock monitoring of wildfire risks from PG&E's Wildfire Safety Operations Center; proactively
3 de-energizing power lines when high winds and dry conditions, combined with a heightened fire risk,
4 are forecasted; enhanced vegetation management work focusing on high-risk trees that pose the most
5 wildfire risk; disabling automatic reclosing of circuit breakers and reclosers in high fire-risk areas
6 during wildfire season; and system hardening efforts that include installing stronger and more
7 fire-resilient poles and covered power lines, as well as targeted undergrounding.

8 *Second*, PG&E welcomes the growing public focus on the acute problem of aging transmission
9 infrastructure. In its filings with the Federal Energy Regulatory Commission ("FERC"), PG&E has
10 sought and continues to seek authorization to set the rates it charges for electric transmission services
11 at levels sufficient to support, among other things, replacement of aging equipment over time. When
12 PG&E files its transmission revenue requirement requests with FERC, the other participants in those
13 proceedings, including the California Public Utilities Commission ("CPUC"), PG&E's wholesale
14 transmission customers, and FERC Trial Staff review the filings while also conducting discovery
15 related to PG&E's requests. In the past, those participants have questioned PG&E's proposed level of
16 spending on transmission assets. For example, in a 2017 ratemaking proceeding, the CPUC stated,
17 "While the CPUC recognizes that repair and replacement are necessary components of a utility's
18 operation, the amount that PG&E has been spending on what appears primarily to be replacement of
19 transmission facilities is staggering and potentially unjustified." (Ex. A, Initial Br. of the CPUC,
20 *Pacific Gas and Electric Co.*, Dkt. No. ER16-2320-002 (Mar. 15, 2018) at 8.) The CPUC also stated
21 there was reason to believe that PG&E was "'gold plating' the system" and "unreasonably burden[ing]
22 ratepayers with unnecessary costs." (*Id.* at 2-3.) This ratemaking process has resulted in settlements
23 at amounts less than what PG&E initially requested. Going forward, PG&E hopes to work with all
24 relevant stakeholders to re-calibrate the level of investment in transmission asset replacement that will
25 be supported in light of the unprecedented wildfire risk California is now facing.

26 *Third*, PG&E strongly disagrees with the *WSJ* Article's suggestion that PG&E knew of the
27 specific maintenance conditions that caused the Camp Fire and nonetheless deferred work that would
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1 have addressed those conditions. The article’s implication that PG&E delayed planned maintenance
 2 that could have averted the Camp Fire is based primarily on certain non-routine work PG&E was
 3 planning for the Caribou-Palermo 115 kV Transmission Line in response to an October 7, 2010 North
 4 American Electric Reliability Corporation (“NERC”) Recommendation to Industry (the “NERC
 5 Alert”). The purpose of that work was not to identify and fix worn or broken parts, such as the hook
 6 on the transmission tower that failed and caused the Camp Fire to ignite. Rather, the purpose of that
 7 work was to address the clearance between transmission line conductors and from transmission line
 8 conductors to the ground. The NERC work on the Caribou-Palermo line was just one of hundreds of
 9 projects within PG&E’s broader effort to respond to the NERC Alert. To date, PG&E has addressed
 10 more than 10,000 conductor clearance issues (out of the approximately 11,500 total), at a cost of over
 11 \$750 million. PG&E provides regular updates on its progress to regulators.

12 Critically, the *WSJ* Article fails to mention that the tower identified as the origin point of the
 13 Camp Fire—Tower :27/222—was *not* one of the towers slated for replacement under the NERC Alert
 14 program. In short, the NERC Alert work had nothing to do with the Camp Fire.

15 **PARAGRAPH 1 OF WALL STREET JOURNAL ARTICLE:**

16 PG&E Corp. knew for years that hundreds of miles of high-voltage power lines could
 17 fail and spark fires, yet it repeatedly failed to perform the necessary upgrades.

18 **RESPONSE TO PARAGRAPH 1:**

19 PG&E admits that it has long known that the approximately 18,000 miles of overhead high-
 20 voltage power lines in its transmission system, like all energized lines, have the potential to fail and
 21 ignite fires.

22 Historically, though, equipment failures on PG&E’s high-voltage transmission lines have
 23 accounted for a small percentage of ignitions as compared to distribution lines. Based on ignition data
 24 for the 2014-2017 period that PG&E has reported to the CPUC, equipment failure on high-voltage
 25 lines operating at 115 kV or above was identified as the underlying cause of only 7 of the 1,552
 26 ignitions attributed to PG&E assets (less than 1% of all ignitions reported in that period). (*See PG&E*
 27 *Fire Incident Data 2014-2018, available at*
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1 https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/PG
 2 [E_Fire%20Incident%20Data%202014-2018.pdf](https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/PG).) The reasons for the comparatively low number of
 3 ignitions attributed to PG&E's high-voltage transmission lines are varied. Such lines typically use
 4 steel structures rather than wood poles, have higher conductor-to-ground clearances than distribution
 5 lines, and are situated on managed rights-of-way that are cleared of trees.

6 By contrast, in the years preceding the Camp Fire, PG&E monitored data showing that a major
 7 driver of ignitions caused by its equipment was vegetation contact with distribution lines. During the
 8 2014-2017 period, PG&E reported 426 ignitions where vegetation came into contact with distribution
 9 assets, comprising approximately 27% of all ignitions reported in that period. (*Id.*) Some of the most
 10 devastating wildfires, including, for example, the Butte Fire, conformed to that pattern. As a result,
 11 PG&E focused earlier wildfire mitigation efforts on its distribution system—and vegetation
 12 management in particular.

13 PG&E denies the generalized assertion that it repeatedly failed to perform the necessary
 14 upgrades to prevent failures on its transmission lines. The suggestion that PG&E has ignored
 15 investment in its transmission lines is inaccurate. Across its transmission system as a whole, PG&E's
 16 actual spending on expense work related to its transmission lines, including routine maintenance,
 17 ranged from \$140 million to \$294 million per year from 2008 to 2018, with a general upward trend
 18 over that period. PG&E's actual capital expenditures on transmission assets grew by an average of
 19 7.35% each year from 2007 to 2018, trending upwards from \$655 million in 2008 to approximately
 20 \$1.29 billion in 2018. PG&E spent the following amounts to upgrade its transmission system from
 21 2006 to 2018:

- 22 • approximately \$1.5 billion on projects to increase transmission system capacity to serve
 23 customer demand (including system rearrangements, new transmission lines, and line re-
 conductor);
- 24 • approximately \$1.34 billion on “line preventative work,” which supports the replacement
 25 of overhead conductors and devices on transmission structures on over 18,000 transmission
 26 line miles operating at voltages from 60 kV to 500 kV. The primary reason for
 replacement is to address the effects of aging;

- approximately \$438 million to replace transmission wood poles, steel poles, and steel towers at the end of their useful lives;
- approximately \$108 million on projects to maintain access to transmission line rights-of-way; and
- approximately \$290 million on emergency response work that includes replacing damaged line-related equipment that has resulted in an outage or is a high priority for safety reasons.

PARAGRAPH 2 OF WALL STREET JOURNAL ARTICLE:

Documents obtained by The Wall Street Journal under the Freedom of Information Act and in connection with a regulatory dispute over PG&E's spending on its electrical grid show that the company has long been aware that parts of its 18,500-mile transmission system have reached the end of their useful lives.

RESPONSE TO PARAGRAPH 2:

PG&E admits reporting in its regulatory filings that parts of its transmission system had reached or were reaching the end of their useful lives. PG&E's publicly available filings also describe its efforts to replace parts of its transmission system at or near the end of useful life that cannot be repaired. As an example, in 2018, PG&E provided FERC with information on its "Tower Replacement Program . . . established to manage the replacement of steel structures that have reached the end of their useful lives . . . where repair is either less cost effective or not feasible." (*See* Ex. B, PGE-0003 (D. Gabbard Direct Testimony), *Pacific Gas and Electric*, Dkt. No. ER19-13-0000 (Oct. 1, 2018) at 12:1-6.)

PARAGRAPH 3 OF WALL STREET JOURNAL ARTICLE:

The failure last year of a century-old transmission line that sparked a wildfire, killed 85 people and destroyed the town of Paradise wasn't an aberration, the documents show. A year earlier, PG&E executives conceded to a state lawyer that the company needed to process many projects, all at once, to prevent system failures—a problem they said could be likened to a "pig in the python."

RESPONSE TO PARAGRAPH 3:

PG&E acknowledges that the failure of a component on a nearly 100-year-old PG&E transmission tower caused the Camp Fire. The component that failed was a steel suspension hook known as a C-hook.

1 PG&E disagrees with the assertion that this failure “wasn’t an aberration.” As stated in
 2 PG&E’s response to Paragraph 1, wildfire ignitions as a result of equipment failure on high-voltage
 3 transmission lines are relatively uncommon. (*See also* 2018 Annual Availability Report, *available at*
 4 <http://www.caiso.com/Documents/PG-E-TransmissionAvailabilityReport.pdf> (“Electric transmission
 5 (ET) wire down events typically account for between 1% and 2% of all T&D wire down events each
 6 year.”).)

7 PG&E acknowledges that in connection with a FERC revenue requirement request, PG&E
 8 Senior Director David Gabbard gave written and oral testimony about projected replacement
 9 schedules for PG&E transmission infrastructure constructed in the early 1900s and in the years
 10 following World War II. Specifically, Mr. Gabbard explained in written testimony that “[a]
 11 significant part of PG&E’s transmission infrastructure was constructed in the years following World
 12 War II, with some assets being even older” and that “[d]ue to an increasingly large number of these
 13 assets nearing the end of their useful service lives, capital investment will shift significantly, from
 14 capacity increase-related projects, to lifecycle replacement projects.” (Ex. C, Prepared Rebuttal Test.
 15 of D. Gabbard, *Pacific Gas and Electric Co.*, Dkt. No. ER16-2320-002 (Oct. 9, 2017) at 7:3-18.)

16 PG&E clarifies that it was not PG&E executives who initially likened the problem of aging
 17 transmission equipment due for replacement at approximately the same time “to a ‘pig in the python.’”
 18 That analogy was suggested by a CPUC attorney during cross-examination of Mr. Gabbard in a
 19 January 2018 regulatory rate proceeding. The relevant portion of the hearing transcript is set forth
 20 below:

21 “Q. Yes. What years are you talking about when you say that
 22 PG&E’s—a significant part of PG&E’s transmission infrastructure was
 constructed in the years following World War II?

23 “A. Referencing a broad era of time in the ‘50s and ‘60s. That’s
 24 referencing a large portion of our assets, but we have a significant
 25 portion of our 115 kV assets that were built as early as in the 1920s time
 frame and earlier.

26 “Q. This is what I described in your deposition as the pig and the
 27 python problem. There were a lot of assets built at the same time during
 this World War II period, in the ‘50s and ‘60s and that these assets will
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1 potentially need to be replaced around the same time. Is that an accurate
2 description of the problem?

3 “A. Yes.” (Ex. D, Hr’g Tr. (D. Gabbard Test.), *Pacific Gas and*
4 *Electric Co.*, Dkt. No. ER16-2320-002 (Jan. 23, 2018) at 1341:25-
1342:14.)

5 **PARAGRAPH 4 OF WALL STREET JOURNAL ARTICLE:**

6 Even before November’s deadly fire, the documents show, the company knew that 49
7 of the steel towers that carry the electrical line that failed needed to be replaced
entirely.

8 **RESPONSE TO PARAGRAPH 4:**

9 PG&E acknowledges that, prior to November 2018, it had identified approximately 60 towers
10 for replacement on the Caribou-Palermo 115 kV Transmission Line. Tower :27/222, the tower
11 identified as the origin point of the Camp Fire, was not one of the towers slated for replacement.

12 The towers were identified for replacement in connection with PG&E’s response to the NERC
13 Alert. The industry-wide NERC Alert required PG&E and other electric utilities across the nation to
14 identify areas in their transmission system where conductors may be too close to the ground or to each
15 other, or have the potential to sag too close to the ground under extreme temperatures. In response to
16 the NERC Alert, PG&E identified thousands of towers on hundreds of lines throughout its
17 transmission system—including the Caribou-Palermo line—that required work to increase the vertical
18 clearance of conductors. To address vertical conductor clearance issues, PG&E typically installs
19 extensions on towers to make them taller or raises the height of the wires by tightening or “re-
20 tensioning” them. Tower replacements are typically done when PG&E determines that other
21 mitigations are not feasible.

22 For the Caribou-Palermo towers identified for replacement, PG&E determined that those
23 towers should be replaced because the design of the towers made them unsuitable for tower extensions
24 to raise the height of the towers, as explained in greater detail in PG&E’s response to Paragraph 24.
25 Again, none of these towers slated for replacement was the tower at which the Camp Fire originated.
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PARAGRAPH 5 OF WALL STREET JOURNAL ARTICLE:

In a 2017 internal presentation, the large San Francisco-based utility estimated that its transmission towers were an average of 68 years old. Their mean life expectancy was 65 years. The oldest steel towers were 108 years old.

RESPONSE TO PARAGRAPH 5:

PG&E admits that a slide in an internal PG&E presentation titled “Electric Overhead Steel Structure Strategy Overview”, dated June 2017, contains the figures referenced in the *WSJ* Article. (*See* Ex. E, Electric Overhead Steel Structure Strategy Overview (June 2017) at 7.) As noted on the same slide, the life expectancy and age estimates referenced in the June 2017 presentation are based on a section of a May 2010 “Transmission Line Component Management Report” prepared at PG&E’s request by Quanta Technology (the “Quanta Study”).

However, the Quanta Study notes that the life expectancy estimates in the study (on which the figures in the June 2017 presentation are based) do not refer to the point at which “complete failure of a structure” is anticipated. (Ex. F, Quanta Study, “Structures” Chapter, at 37.) Rather, they are averages “based on the ages of failed *components* as found in maintenance records from 2004-2009”, with “failure” referring to the point at which a component “requir[es] significant maintenance or replacement”. (*Id.* (emphasis added).) The conditions that qualified as “failures” for the purposes of the Quanta Study included slack guy wires, earth-covered anchors, cracked foundations and bent steel, all of which can be addressed through maintenance work and typically do not require replacement of the entire structure. Moreover, the Quanta Study specifically notes that “[t]here are many structures 100 years old that have not failed or, more likely, have had component replacement o[r] significant maintenance prior to the period of this data set” and that “[l]attice steel structures installed in the 1920s in the US utility industry remain in service in many locations.” (*Id.* at 20, 38.)

The same slide referenced in the *WSJ* Article also notes that the life expectancy for towers varies substantially depending on the surrounding environment. The slide states that the “max” life expectancy for towers in “coastal” environments is 80 years, while the “max” life expectancy for towers in “valley” environments is “100+ years.” (Ex. E, Electric Overhead Steel Structure Strategy

1 Overview (June 2017) at 7.) These variable estimates are consistent with the Quanta Study, which
2 found that the failure rates for towers in “coastal regions” are “significantly higher” than the failure
3 rates for structures “in the valley and mountain regions,” principally because coastal environments are
4 more corrosive than mountain and valley regions. (Ex. F, Quanta Study, “Structures” Chapter, at 46,
5 49.) Tower :27/222 on the Caribou-Palermo 115 kV Transmission Line is located in a mountain
6 region.

7 In the years leading up to the Camp Fire, PG&E was implementing a Tower Replacement
8 Program to replace certain towers that it determined to be at heightened risk of failure. Consistent
9 with Quanta’s recommendations, and as noted in the June 2017 presentation, towers in coastal
10 environments that were subject to corrosion (and thus at greater risk of failure) were higher priorities
11 for replacement under that program. (See Ex. E, Electric Overhead Steel Structure Strategy Overview
12 (June 2017) at 4, 15.) Specifically, PG&E focused on towers in the San Francisco Bay area due to
13 their direct exposure to saltwater from the bay. (See *id.*) Over the medium to long term, PG&E’s
14 Tower Replacement Program called for replacement of additional towers in valley and mountain areas
15 according to a data-driven, risk-weighted prioritization.

16 **PARAGRAPH 6 OF WALL STREET JOURNAL ARTICLE:**

17 PG&E, which supplies electricity and natural gas to 16 million people, or about one in
18 20 Americans, operates one of the oldest long-distance electrical transmission networks
19 in the world. It was built beginning in the early 1900s to carry hydroelectric power
from the Sierra Nevada to the San Francisco Bay Area. Many of its original steel
towers and other equipment are still in service.

20 **RESPONSE TO PARAGRAPH 6:**

21 PG&E is not in a position to comment on the age of transmission systems other than its own,
22 but acknowledges that portions of its transmission system have been in operation since the early
23 1900s. PG&E admits that many of its original steel towers and other equipment are still in service.
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PARAGRAPH 7 OF WALL STREET JOURNAL ARTICLE:

The danger posed by PG&E's neglect of its transmission lines increased around 2013, when a historic drought dried up much of California, creating extraordinary fire conditions. In its 2017 internal presentation, the company said it needed a plan to replace towers and better manage lines to prevent "structure failure resulting [in] conductor on ground causing fire."

RESPONSE TO PARAGRAPH 7:

PG&E admits that the June 2017 internal presentation titled "Electric Transmission Overhead Steel Structure Strategy Overview" outlined a series of PG&E's safety, reliability and environmental objectives for overhead steel transmission lines, including "[e]nsur[ing] the environment is protected from structure failure resulting [in] conductor on ground causing fire." (Ex. E, Electric Overhead Steel Structure Strategy Overview (June 2017) at 3.) PG&E admits that short-term goals listed in that same internal presentation included "[d]evelop[ing] a steel structure replacement plan," managing data associated with steel structures, and "[e]valuat[ing] the effectiveness of [PG&E's existing] design, maintenance and inspection program and mak[ing] necessary recommendations for improvement." (*Id.* at 4.)

PG&E denies that it has "neglect[ed]" its transmission lines. PG&E had programs in place before the Camp Fire to inspect, maintain, repair and replace transmission equipment, as well as to manage vegetation in the vicinity of its transmission lines. PG&E has enhanced those programs since the Camp Fire.

It is true that environmental changes have fundamentally altered wildfire risk in the State of California, including, in particular, PG&E's service territory in recent years. The combined effects of record drought and heat, unprecedented tree mortality, and extreme wind events have greatly exacerbated the risk and destructiveness of California wildfires.

PARAGRAPH 8 OF WALL STREET JOURNAL ARTICLE:

Nevertheless, PG&E repeatedly delayed upgrades of some of its oldest transmission lines, ranking them as low-risk projects, while it spent billions of dollars on other work it considered higher priority, such as substation upgrades, according to federal regulatory filings.

RESPONSE TO PARAGRAPH 8:

PG&E denies the statement that it “repeatedly delayed upgrades of some of its oldest transmission lines, ranking them as low-risk projects,” as an oversimplification and misrepresentation of PG&E’s process for prioritizing repair and replacement of its transmission asset base. PG&E adheres to a maintenance program under which it determines repair and replacement priorities for transmission assets based on a variety of factors. Among the factors that PG&E considers beyond asset age are public and employee safety, system criticality, customer impact, asset health, maintenance records, inspection history, and operational considerations. (Ex. G, PGE-0037, Prepared Rebuttal Test. of K. Dasso, *Pacific Gas and Electric Co.*, Dkt. No. ER16-2320-002 (Oct. 9, 2017) at 13.) While PG&E—like all utilities—has to make decisions about how to prioritize work, it has done so based upon a multi-factored analysis that it has disclosed to its regulators.

PARAGRAPH 9 OF WALL STREET JOURNAL ARTICLE:

Among the problems, the utility has struggled to figure out which of its lines needed the most attention.

RESPONSE TO PARAGRAPH 9:

PG&E denies the generalized assertion that it “has struggled to figure out which of its lines needed the most attention.” To identify and prioritize assets for repair and replacement, PG&E uses data from multiple sources, including PG&E’s Systems, Applications and Products (“SAP”) database, which stores inspection and maintenance records for transmission assets; the Electric Transmission Geographic Information System, which stores known information about asset location, age, manufacturer, ratings, configuration and type; and PG&E’s outage information database. While PG&E strives to collect and maintain comprehensive information on the condition of its transmission assets, the availability and quality of such data varies for a number of reasons, including PG&E’s

1 acquisition over time of smaller utilities that did not keep reliable asset age data. Currently, PG&E is
 2 evaluating how to leverage the improved asset condition information provided by its recent enhanced
 3 inspections.

4 The asset condition data available to PG&E are used as inputs to PG&E's Risk-Informed
 5 Budget Allocation ("RIBA") process. In 2014, PG&E adopted that methodology for prioritizing
 6 projects, including asset replacements, based on consideration of a project's impact on safety,
 7 reliability and the environment. Other prioritization considerations include any mandatory work
 8 commitments, compliance requirements, external commitments and the interrelationship among
 9 projects.

10 **PARAGRAPH 10 OF WALL STREET JOURNAL ARTICLE:**

11 Until recently, PG&E hadn't regularly climbed its towers to inspect their condition,
 12 despite the suggestion of an outside consultant it hired, according to interviews with
 13 current and former company officials and documents filed in connection with a
 spending dispute between PG&E and state regulators. It began detailed inspections of
 its transmission lines only after the Camp Fire that destroyed Paradise.

14 **RESPONSE TO PARAGRAPH 10:**

15 PG&E admits that its policies did not require routine climbing inspections of transmission
 16 lines below 500 kV before the Camp Fire. Even before the Camp Fire, however, PG&E's policies did
 17 require climbing inspections on its 500 kV lines at intervals of every three years for "critical steel
 18 structures" and every 12 years for "non-critical steel structures". In addition, PG&E's policy called
 19 for conducting climbing inspections on all transmission lines, including 115 kV lines, in response to
 20 specific "triggering" events such as component defects identified by inspection, component failure,
 21 fire hazards and suspected vegetation clearance issues. And, in the months before the Camp Fire,
 22 PG&E performed non-routine climbing inspections of approximately 80 structures on the Caribou-
 23 Palermo 115 kV Transmission Line (not including Tower :27/222) as part of an effort to assess the
 24 condition of aging transmission lines.

25 PG&E denies that it "began detailed inspections of its transmission lines only after the Camp
 26 Fire that destroyed Paradise." Prior to the Camp Fire, PG&E policy called for detailed ground
 27 inspections of overhead transmission lines between 60 and 230 kV at least every five years, as well as
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1 aerial patrols of such lines every year in which a detailed inspection was not performed. In addition to
2 inspecting and patrolling every transmission line mile on a routine basis, PG&E policy called for
3 infrared (“IR”) inspections every five years for all transmission assets and as triggered by specific
4 events.

5 PG&E has significantly enhanced its inspection efforts in Tier 2 and Tier 3 High Fire-Threat
6 Districts since the Camp Fire. As PG&E has publicly disclosed, those efforts have identified
7 thousands of conditions requiring repairs on PG&E’s system that had not been previously identified.

8 **PARAGRAPH 11 OF WALL STREET JOURNAL ARTICLE:**

9 In addition to those inspections, PG&E said it began using drones and helicopters
10 earlier this year to capture images of its transmission structures to analyze their
condition, identify potential points of failure and prioritize repairs.

11 **RESPONSE TO PARAGRAPH 11:**

12 PG&E admits Paragraph 11.

13 **PARAGRAPH 12 OF WALL STREET JOURNAL ARTICLE:**

14 State fire officials concluded in May that a failure of PG&E equipment on a line known
15 as the Caribou-Palermo, built in 1921, caused the fire, the deadliest in California
history.

16 **RESPONSE TO PARAGRAPH 12:**

17 PG&E admits Paragraph 12.

18 **PARAGRAPH 13 OF WALL STREET JOURNAL ARTICLE:**

19 Federal and state regulators have paid little attention to the condition of PG&E’s
20 transmission system, and have largely left it up to the company to decide what to
21 upgrade and when. California officials are proposing adding more inspections and
oversight.

22 **RESPONSE TO PARAGRAPH 13:**

23 PG&E has no specific knowledge of any plans that California officials may be contemplating
24 regarding inspection or oversight of utilities.

25 PG&E disagrees with the assertion that “[f]ederal and state regulators have paid little attention
26 to the condition of PG&E’s transmission system” and “have largely left it up to the company to decide
27 what to upgrade and when.” PG&E’s transmission system is governed by federal and state regulations
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1 and a regulatory oversight regime. For example, CPUC General Order 95 (“GO 95”) imposes
2 requirements to which utilities like PG&E must adhere in constructing and maintaining overhead
3 power lines, including transmission lines. Those requirements apply to, among other things, the
4 vertical clearance of transmission line conductors (Section III, Rule 38), vegetation management
5 around transmission lines (Section III, Rule 35), and the requisite strength of materials used on electric
6 transmission systems, including on steel transmission towers (Section IV, Rule 48).

7 The CPUC enforces compliance with the foregoing standards through regular audits of
8 PG&E’s transmission facilities. CPUC staff may review PG&E’s inspection and maintenance records
9 at any time on 30 days’ notice. *See* Public Utilities Code § 314(a); GO 165 § IV; GO 95, Section I,
10 Rule 18(A)(1). Since 2010, the CPUC has elected to review PG&E’s inspection and maintenance
11 records and visit PG&E transmission facilities at least five times.

12 PG&E’s transmission system is also subject to oversight by the California Independent System
13 Operator (“CAISO”). CAISO, which was created by California state law and approved by FERC as a
14 FERC-jurisdictional Independent System Operator, coordinates transmission activities among its state
15 utility members, including PG&E, to help ensure the safe and reliable operation of the broader electric
16 grid. Each utility with facilities under CAISO’s operational control, including PG&E, must submit
17 detailed information regarding its maintenance practices to CAISO through filing a Transmission
18 Owner Maintenance Plan (“TOMP”), and also to the Western Electric Coordinating Council
19 (“WECC”) through filing a Transmission Maintenance Inspection Plan (“TMIP”). Each such utility is
20 also required to review those plans annually and is responsible for notifying CAISO and WECC of
21 any changes to its plans. (May 21, 2007 ISO Memorandum; WECC Standard FAC 501.) Further,
22 under FERC Order Number 890, CAISO also reviews certain proposed transmission projects by each
23 Transmission Owner, such as proposed system capacity upgrades, as part of an overall transmission
24 planning process.

25 Each year, CAISO also randomly selects up to 10% of PG&E’s transmission facilities and
26 station facilities (*e.g.*, substations and switching stations) for review. (*See* ISO Maintenance Review
27 Transmission Maintenance Procedure No. 4 § 4.1.2.)
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Moreover, as described above, PG&E's proposed spending on its transmission system is subject to review by federal and state regulators through the process surrounding PG&E's annual transmission owner filings with FERC. Such filings set forth PG&E's spending plans for its transmission system and request FERC authorization of proposed rates that PG&E seeks to charge for its electric transmission services. Far from "le[aving] it up to [PG&E] to decide what to upgrade and when," as the *WSJ* Article claims, the CPUC has intervened in those proceedings to challenge PG&E's requests for rate increases. Indeed, much of the testimony by PG&E employees cited in the *WSJ* Article was given in rate case proceedings where the CPUC disputed PG&E's explanation that required upgrades to its infrastructure justified its proposed rate increase. (*See* Ex. A, Initial Br. of the CPUC, *Pacific Gas and Electric Co.*, Dkt. No. ER16-2320-002 (Mar. 15, 2018) at 2-3.)

PARAGRAPH 14 OF WALL STREET JOURNAL ARTICLE:

Utilities across the U.S. have neglected to maintain older high-voltage lines, many built to support booming population growth in the decades before and after World War II, said Gregory Reed, director of the Energy GRID Institute at the University of Pittsburgh.

RESPONSE TO PARAGRAPH 14:

PG&E is not in a position to comment on whether the *WSJ* Article accurately paraphrased Mr. Reed or presented his paraphrased statements in the context of his complete remarks.

PARAGRAPH 15 OF WALL STREET JOURNAL ARTICLE:

"We have known for a long time that we are dealing with aging and antiquated infrastructure," he said. "In a lot of cases, the business model was to wait for a failure and then respond."

RESPONSE TO PARAGRAPH 15:

PG&E is not in a position to comment on whether the *WSJ* Article accurately quoted Mr. Reed or presented his statements in the context of his complete remarks.

1 **PARAGRAPH 16 OF WALL STREET JOURNAL ARTICLE:**

2 PG&E sought bankruptcy protection in January, citing more than \$30 billion in
3 potential liability stemming from lawsuits and other claims related to its role in
4 sparking fires. The company in December began “enhanced inspections” that included
climbing towers, some for the first time in decades.

5 **RESPONSE TO PARAGRAPH 16:**

6 PG&E acknowledges seeking bankruptcy protection in January 2019 and, in doing so, having
7 cited potential liabilities with respect to the October 2017 wildfires and 2018 Camp Fire.

8 PG&E admits the second sentence in Paragraph 16. PG&E’s enhanced wildfire mitigation
9 efforts have been described extensively in prior filings. (*See, e.g.*, Dkt No. 976 at 47-50.)

10 **PARAGRAPH 17 OF WALL STREET JOURNAL ARTICLE:**

11 After completing those inspections, the company disclosed June 19 that it needs to
12 make thousands of repairs. And it decided to permanently shut down the Caribou-
Palermo line after assessing the amount of work it would take to operate it safely.

13 **RESPONSE TO PARAGRAPH 17:**

14 PG&E admits that, as a result of recently concluded Wildfire Safety Inspection Program
15 (“WSIP”) inspections of the bulk of its transmission, distribution and substation assets in Tier 2 and
16 Tier 3 High Fire-Threat Districts, PG&E identified thousands of conditions requiring corrective
17 action. As PG&E reported on June 19, 2019, by that time, PG&E had addressed all highest-priority
18 conditions associated with its transmission and substation facilities, and all but 3% of the highest-
19 priority distribution conditions.

20 PG&E also admits that it has decided to de-energize the Caribou-Palermo 115 kV
21 Transmission Line permanently.

1 **PARAGRAPH 18 OF WALL STREET JOURNAL ARTICLE:**

2 PG&E said it already has repaired or made spot fixes to the most severe problems it
3 uncovered throughout its system. Risks remain, and the company said it is working to
prioritize and address them as wildfire season progresses.

4 **RESPONSE TO PARAGRAPH 18:**

5 PG&E admits Paragraph 18. As PG&E reported on June 19, 2019, by that time, PG&E had
6 addressed every highest-priority condition on transmission structures and at substations, and 97% of
7 all such conditions on distribution poles. PG&E continues to take corrective actions to address
8 remaining conditions. PG&E is aware of the continuing inherent risk of operating an electrical system
9 in a high fire-threat environment and is committed to doing everything it can to minimize that risk.

10 **PARAGRAPH 19 OF WALL STREET JOURNAL ARTICLE:**

11 “The reality is the number of safety risks that we’ve found from our standpoint is
12 unacceptable,” said Sumeet Singh, vice president of the company’s community wildfire
safety program.

13 **RESPONSE TO PARAGRAPH 19:**

14 PG&E admits Paragraph 19.

15 **PARAGRAPH 20 OF WALL STREET JOURNAL ARTICLE:**

16 Elizaveta Malashenko, the safety and enforcement chief for the California Public
17 Utilities Commission, said that after reviewing the inspection results, she “would not be
comfortable making a statement that [the Caribou-Palermo] was an outlier.”

18 **RESPONSE TO PARAGRAPH 20:**

19 PG&E is not in a position to comment on whether the *WSJ* Article accurately quoted
20 Ms. Malashenko or presented her quoted statement in the context of her complete remarks.
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PARAGRAPH 21 OF WALL STREET JOURNAL ARTICLE:

Ms. Malashenko said the CPUC's safety auditors have historically relied on utility records rather than field inspections, which are far more costly to conduct. After the Camp Fire, the agency has asked the state for \$25 million to create a three-year program to put its own inspectors in the field, in part because of the problems PG&E has discovered within its system.

RESPONSE TO PARAGRAPH 21:

PG&E is not in a position to comment on whether the *WSJ* Article accurately paraphrased Ms. Malashenko or presented her paraphrased statements in context. PG&E has no specific knowledge of whether the CPUC has made any non-public requests to the State of California, including the request referenced in Paragraph 21, or to whom any such requests were made, nor does PG&E know the cost of CPUC field inspections relative to audits of records.

PARAGRAPH 22 OF WALL STREET JOURNAL ARTICLE:

"No matter how you look at it, PG&E has a lot of work to do," she said.

RESPONSE TO PARAGRAPH 22:

PG&E is not in a position to comment on whether the *WSJ* Article accurately quoted Ms. Malashenko or presented her quoted statement in the context of her complete remarks. PG&E does not dispute that it has "a lot of work to do" to address the current, unprecedented level of risk of wildfire in its service territory, including the work described extensively in PG&E's prior filings with this Court.

PARAGRAPH 23 OF WALL STREET JOURNAL ARTICLE:

The part of PG&E's grid that includes the Caribou-Palermo line, known as the Caribou-Valona system, is so old that segments were considered candidates for the National Register of Historic Places at one point by federal agencies. Approximately 800 of the original steel towers built to hold up the transmission lines are still in use, according to PG&E correspondence with federal officials, uncovered through a public-records request.

RESPONSE TO PARAGRAPH 23:

PG&E admits that federal agencies considered parts of the Caribou-Valona system, including the section of the Caribou-Palermo 115 kV Transmission Line from the Caribou Powerhouse to the Big Bend Switching Station, for inclusion on the National Register of Historic Places ("NRHP"). In

1 response to PG&E's request for authorization to perform NERC work on the Caribou-Palermo line,
 2 the United States Forest Service ("USFS") took the position that the Caribou-Big Bend section of the
 3 line is historically significant and should be included on the NRHP "for its association with key
 4 historical events and trends in the development of long-distance hydroelectric transmission lines in
 5 California." (Ex. H, Ltr. from J. Bird, Forest Supervisor, USFS, to J. Polanco, State Historic
 6 Preservation Officer (Mar. 13, 2019) at 2.) Based on that finding and the California State Historic
 7 Preservation Officer's concurrence, PG&E understood that the National Historic Preservation Act
 8 required additional measures to accommodate the line's eligibility for historic status before PG&E
 9 could proceed with the proposed work.

10 PG&E admits that more than 800 original towers on the historical Caribou-Valona
 11 transmission network, which includes the Caribou-Palermo 115 kV Transmission Line and ten other
 12 lines, are still in place. As noted above, following the Camp Fire, the Caribou-Palermo 115 kV
 13 Transmission Line has been permanently de-energized.

14 **PARAGRAPH 24 OF WALL STREET JOURNAL ARTICLE:**

15 PG&E delayed safety work on the Caribou-Palermo line for more than five years, the
 16 Journal reported in February. The company needed to replace 49 steel towers "due to
 17 age," and hardware and aluminum line on 57 towers "due to age and integrity,"
 18 according to memos PG&E officials sent in 2017 and early 2018 to the U.S. Forest
 19 Service, whose territory the line crosses. The Journal learned the scope of the work,
 20 which hasn't previously been reported, through a Freedom of Information Act request
 21 to federal forest managers.

22 **RESPONSE TO PARAGRAPH 24:**

23 PG&E admits that the completion date for NERC Alert-related work on the Caribou-Palermo
 24 115 kV Transmission Line to address vertical conductor clearance issues was delayed due to a variety
 25 of reasons, including engineering, operational and permitting reasons. As stated above, PG&E
 26 identified approximately 60 towers on the Caribou-Palermo line for replacement in response to the
 27 NERC Alert. The purpose of the work was to increase the vertical clearance of conductors. It was not
 28 to identify and repair or replace worn or broken parts. Tower :27/222, which initiated the Camp Fire,

1 was not included within the scope of the project because the conductor clearance on that span was
 2 determined to be compliant with applicable regulations for vertical clearance.

3 PG&E denies that “the company needed to replace 49 steel towers” on the Caribou-Palermo
 4 115 kV Transmission Line because of their age and no other reason. Age, in and of itself, was not the
 5 reason PG&E decided to replace the towers. Rather, the older design of the towers made them
 6 unsuitable for other methods for increasing the vertical clearance of the conductors, such as adding
 7 extensions to raise the height of the towers. As the 2018 Forest Service memorandum states:

8 “Tower replacements are planned due to age and type of the existing steel lattice
 9 towers. The existing towers are approximately 100 years old and are directly buried
 10 grillage with no concrete foundations. *The towers are not considered structurally*
 11 *suited to the addition of lattice steel cage top, waist cage, or other extensions to raise*
the heights of the towers.” (Ex. I, Memorandum Regarding PG&E NERC Program
 (Jan. 3, 2018) at 2 (emphasis added).)

12 Similarly, PG&E also denies that it was planning to replace conductor segments due to age and
 13 integrity and no other reason. The conductor was scheduled to be replaced as a consequence of the
 14 planned installation of taller replacement towers. As the 2018 Forest Service memorandum states, the
 15 conductor on certain spans needed to be replaced because it did “not have adequate strength to
 16 withstand the increased tension resulting from installing taller replacement structures.” (*Id.* at 5.)

17 PG&E is not in a position to comment on whether the *Wall Street Journal* obtained the
 18 referenced memoranda through a Freedom of Information Act request.

19 **PARAGRAPH 25 OF WALL STREET JOURNAL ARTICLE:**

20 PG&E has delayed maintenance work on several lines in Northern California’s highest-
 21 threat fire areas, including at least one near the Plumas National Forest, federal
 22 documents show. The company hasn’t detailed the scope of the work needed for each
 line, but it has disclosed that some require upgrades similar to those needed on the
 Caribou-Palermo line it stopped using.

23 **RESPONSE TO PARAGRAPH 25:**

24 PG&E understands Paragraph 25 to refer to NERC Alert-related work. As stated above, the
 25 purpose of that work was not to identify and fix worn or broken parts, but rather to address issues
 26 related to the clearance (ground-to-wire or wire-to-wire) of conductors.

1 PG&E acknowledges that the planning, timing and completion date for specific NERC Alert
2 projects has changed for a variety of reasons, including prioritization of work across the system and
3 engineering, permitting and operational reasons. Overall, PG&E has made significant progress toward
4 addressing NERC Alert work across its system, and has provided regular updates on its progress to
5 WECC. Specifically, PG&E has addressed more than 10,000 conductor clearance issues out of the
6 approximately 11,500 identified for work as part of that program (approximately 88%) along hundreds
7 of circuits, at a cost of over \$750 million.

8 PG&E has completed all NERC mitigation work on 7 of the 11 in-service transmission lines in
9 the vicinity of Plumas National Forest on which PG&E identified conductor clearance issues,
10 addressing a total of approximately 120 identified clearance issues on those lines. PG&E has some
11 outstanding NERC mitigation work on three in-service transmission lines in the vicinity of Plumas
12 National Forest. On those three lines, PG&E has thus far addressed all but approximately five of the
13 identified clearance issues.

14 **PARAGRAPH 26 OF WALL STREET JOURNAL ARTICLE:**

15 The deferred maintenance became a problem when drought this decade killed millions
16 of trees, greatly heightening the risk of wildfire throughout Northern California State
17 fire officials concluded that the company's equipment sparked 18 wildfires in 2017, in
most cases because trees made contact with lower-voltage lines.

18 **RESPONSE TO PARAGRAPH 26:**

19 PG&E denies that it has "deferred maintenance" on its transmission lines and refers to its
20 response to Paragraph 1. PG&E admits Paragraph 26 with respect to the heightened risk of wildfire
21 resulting from drought and tree mortality and refers to its response to Paragraph 7. PG&E further
22 admits that CAL FIRE has concluded that PG&E electrical equipment caused 18 wildfires in 2017, the
23 majority of which CAL FIRE has attributed to trees coming into contact with distribution lines.
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PARAGRAPH 27 OF WALL STREET JOURNAL ARTICLE:

In response, the company doubled down on tree trimming. The Camp Fire forced PG&E to turn its attention to higher-voltage lines, which typically run through wide paths cleared of trees.

RESPONSE TO PARAGRAPH 27:

PG&E admits that it enhanced its tree trimming and vegetation management work on distribution lines in response to the October 2017 wildfires. PG&E further admits that its transmission lines typically run through managed rights-of-way cleared of trees. As PG&E has described at length in this and other filings, PG&E significantly enhanced its wildfire mitigation efforts, including with respect to transmission facilities, following the Camp Fire.

PARAGRAPH 28 OF WALL STREET JOURNAL ARTICLE:

Documents show that PG&E is unaware of the exact age of many of its transmission towers and wires. In 2010, PG&E commissioned consulting firm Quanta Technology, a subsidiary of Quanta Services Inc., to assess the age and condition of transmission structures throughout its 70,000-square-mile service area.

RESPONSE TO PARAGRAPH 28:

PG&E admits that it is not always able to determine the exact age of towers and wires on its transmission lines, including lines that it has acquired from other companies over the course of more than 100 years, and that PG&E commissioned Quanta Technology to assess the age and condition of transmission structures (as well as other transmission components and assets) throughout its service territory.

PARAGRAPH 29 OF WALL STREET JOURNAL ARTICLE:

The firm was unable to determine the age of about 6,900 towers in the 115-kilovolt system. It found that nearly 30% of the remaining towers in that system, more than 3,500, were installed in the 1900s and 1910s. About 60% of the structures in the 230-kilovolt system were built between 1920 and 1950.

RESPONSE TO PARAGRAPH 29:

PG&E admits Paragraph 29 and refers to its response to Paragraph 28. PG&E further notes Quanta Technology's observation that "[l]attice steel structures installed in the 1920s in the US utility industry remain in service in many locations" and that transmission tower age data from six utilities,

1 including PG&E, “demonstrate[d] that structures remain in service in the utility industry well into
2 seven or eight decades, even longer in some cases.” (Ex. F, Quanta Study, “Structures” Chapter,
3 at 20-21.)

4 **PARAGRAPH 30 OF WALL STREET JOURNAL ARTICLE:**

5 It is common practice for utilities to use laser imaging equipment to inspect towers
6 instead of having workers climb them. Because PG&E had so many old towers,
7 Quanta concluded that the company should consider climbing at least a sample of them
every three to five years.

8 **RESPONSE TO PARAGRAPH 30:**

9 PG&E admits that Light Detection and Ranging (“LiDAR”) laser imaging technology is
10 commonly used by utilities, including PG&E, to inspect transmission towers and detect vegetation
11 encroachment on transmission rights-of-way. PG&E has not used LiDAR technology as a substitute
12 for climbing inspections. Even before the Camp Fire, PG&E performed routine ground inspections
13 with binoculars and aerial patrols of its transmission lines at regular intervals. As discussed in its
14 response to Paragraph 10, PG&E’s policies called for routine climbing inspections of towers on
15 500 kV transmission lines and non-routine climbing inspections of towers on all transmission lines in
16 in response to specific triggering events.

17 PG&E admits that the 2010 Quanta Study states that “[a]n effective strategy for structure and
18 foundation management would include elements such as . . . [c]omprehensive climbing inspection at
19 3-5 year intervals.” (Ex. F, Quanta Study, “Structures” Chapter, at 48.) The same sentence in that
20 study recommends several other “elements” that were and continue to be a part of PG&E’s asset
21 management and maintenance programs, including “[r]outine visual inspections by ground and aerial
22 patrol as part of general line inspection process,” “[r]ecoating or painting at intervals determined by
23 the degradation of the coating thickness,” and “[l]aboratory testing of components removed from
24 service as part of repair or replacement work to determine overall condition and remaining strength of
25 material,” among others. (*Id.* at 48-49.)
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PARAGRAPH 31 OF WALL STREET JOURNAL ARTICLE:

PG&E didn't implement that recommendation, said Placido J. Martinez, a former PG&E head of strategic asset management. "We felt we were doing enough," he said.

RESPONSE TO PARAGRAPH 31:

PG&E understands that Mr. Martinez told the *Wall Street Journal* that he could not recall the 2010 Quanta Study or its recommendations, but that he felt PG&E was doing enough with regard to its transmission inspection practices.

PG&E admits that its policies prior to the Camp Fire did not require routine climbing inspections of transmission lines below 500 kV. PG&E's policies did require, for all transmission lines, climbing inspections in response to specific triggering events.

PARAGRAPH 32 OF WALL STREET JOURNAL ARTICLE:

Regulators have little say over such transmission-maintenance planning. Although PG&E files transmission-spending plans with the Federal Energy Regulatory Commission, the agency's jurisdiction is over rates and terms of service. If state officials or electric companies that rely on PG&E's wires want to challenge the utility's spending, it is up to them to parse the annual federal filings, which often exceed 1,500 pages. Projects that involve routine maintenance, such as replacing aging towers, hardware and conductors, don't require state or federal approval.

RESPONSE TO PARAGRAPH 32:

PG&E denies that "[r]egulators have little say over . . . transmission-maintenance planning" and the implication that FERC's jurisdiction is limited to "rates and terms of service." FERC is responsible for approving and enforcing reliability standards for the bulk-power system, which includes components of PG&E's transmission system. *See* 16 U.S.C. § 824o. These reliability standards include standards governing vegetation management and transmission maintenance planning, *see* FAC003-4; FAC-501-WECC2, and are enforceable by civil penalties of up to \$1 million per day per violation. 16 U.S.C. § 825o-1. Additionally, the Federal Power Act requires that the rates electric utilities charge for the transmission or sale of electric energy be "just and reasonable," and confers authority on FERC to make such determinations. 16 U.S.C. § 824d. FERC has substantial

1 influence over PG&E's transmission maintenance planning because the rates it authorizes will
 2 ultimately determine the extent to which PG&E can recover the costs of planned capital and
 3 maintenance work on its transmission lines and, thus, the proportion of that work that is economically
 4 sustainable for PG&E to perform.

5 Under that regulatory framework for cost recovery, PG&E is required to provide detailed
 6 information on proposed spending in its transmission revenue requirement filings. PG&E provides
 7 that information because that is what FERC and federal law require. *See* 18 C.F.R. § 35.1 (requiring
 8 utilities to file "full and complete rate schedules and tariffs . . . clearly and specifically setting forth all
 9 rates and charges for any transmission or sale of electric energy subject to the jurisdiction of this
 10 Commission," as well as "the classifications, practices, rules and regulations affecting such rates").
 11 Federal regulations further require that PG&E provide significant data in support of requested rate
 12 increases, including comparative information about past rates, detailed cost of service information,
 13 "work papers" that provide "a comprehensive explanation of the bases for the adjustments or
 14 estimates," and supporting testimony and exhibits. *See* 18 C.F.R. § 35.13.

15 PG&E also disagrees with the overbroad statement that "[p]rojects that involve routine
 16 maintenance, such as replacing aging towers, hardware and conductors, don't require state or federal
 17 approval." While specific types of routine maintenance such as component replacement may not
 18 require such approval, projects that involve replacement of entire transmission towers, taking lines out
 19 of service, or performing work on federal land may require coordination with and, in certain
 20 circumstances, approval by state and federal regulators, including the CPUC, CAISO and USFS.

21 **PARAGRAPH 33 OF WALL STREET JOURNAL ARTICLE:**

22 California regulators have hundreds of pages of rules for many aspects of utility
 23 operations. Their rules for transmission are three sentences long. They simply say that
 each utility must come up with its own procedures and follow them.

24 **RESPONSE TO PARAGRAPH 33:**

25 PG&E denies Paragraph 33. PG&E understands the statement that "California regulators' . . .
 26 rules for transmission are three sentences long" to be a reference to Part IV of CPUC General Order
 27 165 ("GO 165"). That Part, titled "Transmission Facilities", provides as follows:
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1 “Each utility shall prepare and follow procedures for conducting inspections and
 2 maintenance activities for transmission lines. Each utility shall maintain records of
 3 inspection and maintenance activities. Commission staff shall be permitted to inspect
 records and procedures consistent with Public Utilities Code Section 314 (a).”

4 While that specific provision in GO 165 is brief, there exist other, more detailed CPUC
 5 General Orders that regulate California utilities’ transmission operations. Among those other General
 6 Orders is GO 95 on Rules for Overhead Electric Line Construction, which contains detailed
 7 requirements regarding the construction and maintenance of both transmission and distribution lines
 8 (Section I, Rules 12.1, 12.2); minimum safety factors and loading requirements for transmission lines
 9 (Section IV, Rules 43 & 44.1); material and strength requirements for towers, conductors, insulators,
 10 guys and anchors (Section IV, Rules 48 & 49; Section VI, Rules 61.3 & 65); vegetation management
 11 around transmission lines (Section III, Rule 35); and ground-to-conductor, conductor-to-conductor and
 12 other clearance requirements for transmission lines (Section III, Rules 37-39; Section VI, Rule 64.4).
 13 Other General Orders that apply to transmission lines include General Order 131-D on Planning and
 14 Construction of Facilities for the Generation of Electricity and Certain Electric Transmission Facilities
 15 and General Order 128 on Construction of Underground Electric Supply and Communication
 16 Systems.

17 **PARAGRAPH 34 OF WALL STREET JOURNAL ARTICLE:**

18 With no regulator keeping a close eye, the timetable for completing important upgrades
 19 slipped. PG&E told federal regulators it planned to overhaul the Caribou- Palermo line
 20 in 2013, yet it still hadn’t made improvements when a piece of hardware holding a
 high-voltage line failed last November, sending sparks into the grass and igniting the
 Camp Fire.

21 **RESPONSE TO PARAGRAPH 34:**

22 PG&E denies that “no regulator keep[s] a close eye” on PG&E’s transmission operations for
 23 the reasons described above. PG&E regularly submits filings with FERC that contain detailed
 24 information on planned upgrades to PG&E’s transmission lines, including expected timeframes for
 25 completion of work. PG&E is also accountable to other regulators, including the CPUC, which has
 26 intervener status in PG&E’s transmission rate cases; CAISO, which has operational control over
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1 PG&E's transmission facilities; and NERC and WECC, to which PG&E submits regular reports
 2 regarding its progress toward bringing the vertical clearance of its transmission lines into compliance
 3 with GO 95 and NERC requirements.

4 PG&E acknowledges that it informed FERC in 2013 of a plan to relocate certain towers on the
 5 Caribou-Palermo 115 kV Transmission Line. PG&E denies that such work constituted an "overhaul"
 6 of the line. Rather, the project called for replacing and relocating 10 towers along the line, comprising
 7 the approximately one-mile span from Tower :7/55 to Tower :8/64, across the river to a more easily
 8 accessible area near the Caribou-Table Mountain 230 kV Transmission Line. Tower :27/222, the
 9 tower identified as the ignition point of the Camp Fire, is many miles away from those towers and no
 10 work was contemplated on it as part of this tower relocation project. PG&E later determined that
 11 relocation of the towers was unnecessary because it could reasonably access the towers through some
 12 additional roadwork, and the condition of the towers could be addressed through maintenance.

13 **PARAGRAPH 35 OF WALL STREET JOURNAL ARTICLE:**

14 After the Journal reported earlier this year that the planned upgrades to that line had
 15 been delayed, PG&E released a statement saying the work was "not maintenance-
 related (i.e., work relating to identifying and fixing broken or worn parts)."

16 **RESPONSE TO PARAGRAPH 35:**

17 PG&E admits that the *Wall Street Journal* released an article dated February 27, 2019, titled
 18 "PG&E Delayed Safety Work on Power Line That is Prime Suspect in California Wildfire", that
 19 claimed that PG&E had delayed NERC Alert work on the Caribou-Palermo 115 kV Transmission
 20 Line and that PG&E issued a February 27, 2019 statement responding to the allegations in the article
 21 and explaining that the work slated for the Caribou-Palermo line was "not maintenance-related (i.e.,
 22 work relating to identifying and fixing broken or worn parts)."

23 As explained in PG&E's February 27, 2019 statement and in response to Paragraph 4 above,
 24 the project described in the February 27 article was part of a system-wide effort undertaken in
 25 response to the 2010 NERC Alert. The purpose of that project was to address ground-to-conductor
 26 and conductor-to-conductor clearances on transmission towers, not to identify and repair broken or
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worn parts. Tower :27/222, which initiated the Camp Fire, was not within the scope of the project because PG&E determined that the conductor clearance on that span was compliant with applicable regulations for vertical clearance.

PARAGRAPH 36 OF WALL STREET JOURNAL ARTICLE:

Internally, however, that is how the company characterized it. In a 2017 email to Forest Service officials, PG&E land planner Paul Marotto wrote that the company's "planned maintenance includes structure replacement, conductor replacement, conductor re- tensioning, installation of new insulators and structure modifications." PG&E officials said the work was needed in part because the strength of the aging towers and wires had deteriorated.

RESPONSE TO PARAGRAPH 36:

PG&E admits that in an October 18, 2017 email to USFS officials, PG&E Principal Land Planner Paul Marotto wrote that "PG&E's planned maintenance includes structure replacement, conductor replacement, conductor re-tensioning, installation of new insulators and structure modifications." (Ex. J, Email from P. Marotto (Oct. 17, 2017).) Mr. Marotto's email further states that the purpose of the work was "to mitigate NERC discrepancies (ground to wire clearances)." (*Id.*)

As to the statement that "PG&E officials said the work was needed in part because the strength of the aging towers and wires had deteriorated", PG&E refers to its response to Paragraph 24 above.

PARAGRAPH 37 OF WALL STREET JOURNAL ARTICLE:

Asked about the email, PG&E said it still disputes that the work was maintenance related, saying it was needed to adhere to 2010 industry guidelines that called on companies to ensure their transmission lines met design specifications.

RESPONSE TO PARAGRAPH 37:

PG&E admits that it told the *Wall Street Journal* that the NERC Alert work on its transmission lines was not for the purpose of identifying and fixing broken or worn parts, but rather to address issues relating to the clearance of conductors. That statement was accurate.

PARAGRAPH 38 OF WALL STREET JOURNAL ARTICLE:

PG&E has told state regulators it has struggled to consolidate data on the condition of its equipment. Kevin Dasso, PG&E's vice president of electric asset management until earlier this year, said the lack of comprehensive information made it difficult to determine which transmission lines were approaching the point of failure.

RESPONSE TO PARAGRAPH 38:

PG&E understands Paragraph 38 to be referring to the testimony of PG&E Vice President Kevin Dasso in connection with PG&E's eighteenth transmission rate case before FERC. PG&E denies that Mr. Dasso "told state regulators [PG&E] has struggled to consolidate data on the condition of its equipment" or that an alleged "lack of comprehensive information made it difficult to determine which transmission lines were approaching the point of failure."

Instead, Mr. Dasso testified that, while data on asset condition may not be easily retrievable from a database for every type of asset, relevant information is nonetheless available to and accessible by PG&E's engineers, who are trained to compile that data from databases, electronic repositories and hard copy documents. Relevant passages from Mr. Dasso's testimony are set forth below:

"Q. PG&E doesn't have all of the data on a class of assets in one place, does it?

"A. No. That doesn't mean it's not available and can't be pulled together.

"Q. How does a PG&E staff person know where to look for each piece of data that they need in order to run the 1 to N analysis?

"A. It depends on the asset class, and each of those engineers are familiar with the data that is available to them. They know where to find it. They also know that not all of the data is exactly perfect.

"However, they know, as we've provided in responses to data requests, the age of substation transformers, for example. That information is available. It's readily available. The engineers that work in that space have that information available to them, and they use that regularly in their criteria or in their implementation of the replacement criteria.

"Q. A PG&E engineer, program manager who's working on a specific asset class will simply know where to find the data to run the 1 to N analysis?

1 “A. Yes.

2 “Q. It’s not written down anywhere?

3 “A. What do you mean not written down anywhere, the precise
4 directions to that engineer, exactly how to do that?

5 “Q. A listing of where all the data is available for a particular asset
6 class. It’s not identified, so if that project manager gets hit by a bus,
7 somebody else can run the analysis? Are there no procedures in place at
PG&E to have this information shared and ensure that the analysis that
is run looks at all the data and not just selective data?

8 “A. In some cases, we have procedures that lay that out in some detail,
9 and in other cases we do not. We do not have in all cases the exact
10 cookbook instructions for how an engineer precisely does his job to
produce the information necessary to create the recommendations.

11 “However, that’s what we expect our engineers to do. They understand
12 the assets. They understand PG&E. They understand where the data is.
13 They understand how it's labeled, how it’s culled out. They also
14 understand where data may not be available for a particular class of
assets. PG&E is made up of many individual utilities that have been
15 acquired over the years.” (Ex. K, Hr’g Tr. (K. Dasso Test.), *Pacific Gas
and Electric Co.*, Dkt. No. ER16-2320-002 (Jan. 9, 2018) at 236:6-
237:25.)

16 **PARAGRAPH 39 OF WALL STREET JOURNAL ARTICLE:**

17 In 2018, when PG&E proposed a spending plan to federal regulators for thousands of
18 transmission-line upgrades, it used a risk-based system to prioritize the projects.
19 Nearly 600 projects, with an estimated \$2.7 billion cost, had a higher risk score than
Caribou-Palermo, indicating PG&E considered that work more urgent.

20 **RESPONSE TO PARAGRAPH 39:**

21 PG&E admits that it uses a risk-based methodology known as Risk-Informed Budget
22 Allocation, or RIBA, that weighs safety, reliability and environmental risks to prioritize asset
23 management projects on transmission lines.

24 PG&E admits that in response to a March 2018 data request from the CPUC’s Legal Division,
25 PG&E provided data showing that 595 projects with an estimated total cost of approximately
26
27
28

1 \$2.7 billion were assigned higher RIBA scores than NERC Alert-related work on the Caribou-Big
2 Bend section of the Caribou-Palermo line.

3 **PARAGRAPH 40 OF WALL STREET JOURNAL ARTICLE:**

4 PG&E said it has improved its records in recent years by conducting inventories in the
5 field and has built databases to upgrade its analytical capabilities.

6 **RESPONSE TO PARAGRAPH 40:**

7 PG&E admits that it told the *Wall Street Journal* that it has taken a number of steps to improve
8 its records regarding the age and condition of its assets. That statement was accurate. PG&E
9 acknowledges it has more work to do to improve in these areas.

10 **PARAGRAPH 41 OF WALL STREET JOURNAL ARTICLE:**

11 Other PG&E transmission lines at least as old as the Caribou-Palermo remain in
12 service. One leg of the Caribou-Valona network, known as the Ignacio-Mare Island
13 line, delivers power to an electric switchyard at the edge of a high-fire-risk area in
14 Marin County north of the Golden Gate Bridge and a now-closed naval shipyard. At
least 28 of the towers on the line have been in place since 1921, according to a
company inventory.

15 **RESPONSE TO PARAGRAPH 41:**

16 PG&E admits Paragraph 41 and notes that no structure on either of the two Ignacio-Mare
17 Island 115 kV Transmission Lines is situated in a Tier 2 or Tier 3 High Fire-Threat District. As
18 discussed in its response to Paragraph 42, much of the circuit runs through wetlands.

19 **PARAGRAPH 42 OF WALL STREET JOURNAL ARTICLE:**

20 PG&E has repeatedly delayed work on the line, which has segments sagging too close
21 to the ground, since first proposing it in 2014, federal regulatory filings show. The
22 \$6.9 million project, which involves increasing the height of 44 towers, was initially
expected to be completed in 2015 but now is slated to start next year, the company said.

23 **RESPONSE TO PARAGRAPH 42:**

24 PG&E understands Paragraph 42 to be referring to NERC Alert work on the Ignacio-Mare
25 Island 115 kV Transmission Lines. The planned NERC mitigations for PG&E transmission lines will
26 address vertical conductor clearance issues on 185 towers through a combination of tower
27 modifications and replacements and conductor replacements. PG&E admits that since work on the
28

line was first proposed in 2014, it has been delayed due to engineering, operational and environmental reasons, as well as the need to prioritize work on the hundreds of lines within the scope of PG&E's NERC Alert program. Among other issues, extensive permitting is required for this work because many of the towers on the Ignacio-Mare Island 115 kV Transmission Lines run through the Napa-Sonoma Marshes Wildlife Area and the San Pablo Bay National Wildlife Refuge, both sensitive wetland environments with endangered species. Geological studies in these environmentally sensitive areas that require permits are also required before engineering can continue. PG&E submitted its application in June 2018 and received all approvals needed to proceed with those studies in May 2019. This work is currently forecasted to be completed in three phases from 2020 to 2023.

PG&E further notes that the \$6.9 million referenced in Paragraph 42 refers to the projected cost for only one of these phases as of the date of the relevant regulatory filing. The total cost for all three phases combined is currently projected to be between \$40 and 50 million.

PARAGRAPH 43 OF WALL STREET JOURNAL ARTICLE:

The company also has delayed upgrades to several 115-kilovolt lines passing through national forests that have become California's highest-risk fire areas, the filings indicate. A line partly in the Plumas National Forest was slated for work this year, but was delayed and now is on hold because of the Camp Fire investigation.

RESPONSE TO PARAGRAPH 43:

PG&E understands "upgrades" in this paragraph to be a reference to NERC Alert-related work to raise the vertical clearance of conductors. PG&E further understands the "line partly in the Plumas National Forest . . . slated for work this year" and "now . . . on hold because of the Camp Fire investigation" to be the southern section of the Caribou-Palermo 115 kV Transmission Line running from Big Bend Switching Station to Palermo Substation. Tower :27/222, which initiated the Camp Fire, is not located on this section of the Caribou-Palermo 115 kV Transmission Line. NERC Alert-related work on that section was originally scheduled to be completed in November 2018 but was delayed. PG&E prioritizes projects for completion based on its Risk-Informed Budget Allocation process, and provides forecasted dates in its FERC revenue requirement filings by which it expects

1 each project to become operational. PG&E re-prioritizes projects for a variety of reasons, including
2 delays in obtaining necessary permits, unanticipated engineering challenges, and the need to obtain
3 clearances to perform the work, among other reasons. Shortly after the Camp Fire, PG&E suspended
4 the project in the interest of preserving potential evidence related to the Camp Fire. The entire
5 Caribou-Palermo 115 kV Transmission Line has been permanently de-energized since December
6 2018, making this work unnecessary.

7 **PARAGRAPH 44 OF WALL STREET JOURNAL ARTICLE:**

8 A line built to carry hydroelectric power through the Eldorado and Stanislaus national
9 forests was scheduled for upgrades in 2016, but work isn't expected to start until the
10 second half of next year. A line in the Los Padres National Forest near San Luis
Obispo was initially set for upgrades in 2015 that now are scheduled to start in 2021.

11 **RESPONSE TO PARAGRAPH 44:**

12 Based on the date and location information in Paragraph 44 and a prior request for comment
13 from the *Wall Street Journal*, PG&E understands this Paragraph to refer to work that includes
14 addressing NERC Alert-related vertical clearance issues on the 115 kV Salt Springs-Tiger Creek and
15 Temblor-San Luis Obispo transmission lines.

16 PG&E acknowledges that work to address vertical clearance issues on the Salt Springs-Tiger
17 Creek and Temblor-San Luis Obispo transmission lines has not yet started and is now scheduled for
18 completion in 2020 and 2021, respectively.

19 In the case of the Salt Springs-Tiger Creek 115 kV Transmission Line, in 2016, PG&E
20 reassessed the most effective engineering approach for mitigating the conductor clearance issues
21 identified on the line. As a result of that reassessment, PG&E adopted a new method for mitigation
22 that increased the project's scope and required additional soil studies, for which additional permits
23 were necessary. PG&E performed borings in connection with this project in 2018, and currently
24 expects to complete the project in 2020.

25 With respect to NERC mitigation work on the Temblor San-Luis Obispo 115 kV Transmission
26 Line, the project required extensive engineering analysis to determine the most effective method for
27
28

1 mitigating the identified conductor clearance issues. The current operational date of 2021 was chosen
2 based on the anticipated time required to acquire a permit from the USFS to proceed with the project.

3 **PARAGRAPH 45 OF WALL STREET JOURNAL ARTICLE:**

4 PG&E acknowledged in its 2017 internal presentation that it had poor age data on the
5 towers in its 60-kilovolt system. The company recently targeted one leg for extensive
6 work after discovering that 10 towers within the Golden Gate National Recreation Area
were at high risk of failure.

7 **RESPONSE TO PARAGRAPH 45:**

8 PG&E admits that the June 2017 internal presentation titled “Electric Transmission Overhead
9 Steel Structure Strategy Overview,” referenced in this Paragraph as well as Paragraph 5, states that
10 PG&E has “[p]oor age data on 60 and 70 kV structures.” (Ex. E, Electric Overhead Steel Structure
11 Strategy Overview (June 2017) at 7.) PG&E’s transmission system is composed of hundreds of lines
12 that PG&E acquired over the course of a century. Many of those lines were acquired from companies
13 that did not keep records of when their towers were installed.

14 PG&E acknowledges that, in May 2019, it identified nine towers on the Ignacio-Alto-Sausalito
15 60 kV Transmission Line located within the Golden Gate National Recreation Area (“GGNRA”) in
16 critical condition and requiring replacement. A tenth tower on the line within the GGNRA was found
17 to require lower-priority safety work and will also be replaced. Pending permanent replacements,
18 PG&E is installing temporary replacement structures for towers identified for replacement within the
19 GGNRA. While work is underway on disassembling the existing towers, PG&E is monitoring the
20 towers around the clock to protect public safety.

1 **PARAGRAPH 46 OF WALL STREET JOURNAL ARTICLE:**

2 A June 5 letter from PG&E said the towers are in “critical condition with noticeable
3 material loss and ground erosion” and require round-the-clock monitoring. The
4 company estimated it will take more than a year to replace towers and make permanent
repairs.

5 **RESPONSE TO PARAGRAPH 46:**

6 PG&E admits Paragraph 46, which refers to a letter from PG&E to the GGNRA, except
7 clarifies that the letter is dated June 6, 2019.

Dated: July 31, 2019

Respectfully Submitted,

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EXHIBIT A

STATE OF CALIFORNIA

EDMUND G. BROWN JR., *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
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March 15, 2018

Via Electronic Delivery

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A, East
Washington, D.C. 20002

Re: *Pacific Gas and Electric Company*
Docket No. ER16-2320-002

Dear Ms. Bose:

The California Public Utilities Commission ("CPUC") hereby submits for filing the attached "INITIAL BRIEF AND PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION."

Thank you for your cooperation in this matter, and please do not hesitate to contact me at (415) 703-2048 or tbo@cpuc.ca.gov if you have any questions or concerns regarding the foregoing.

Sincerely,

/s/ Traci Bone

Traci Bone
Staff Attorney

cc: Hon. David H. Coffman, Presiding Administrative Law Judge
Mr. Christopher Chaulk, Law Clerk
Marshina Griffin, Legal Assistant
Service List

PUBLIC VERSION – CUI/PRIV PORTIONS REDACTED

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**Pacific Gas and Electric Company)
_____)**

**Docket Nos. ER16-2320-000
ER16-2320-002**

**INITIAL BRIEF AND PROPOSED FINDINGS OF FACT
AND CONCLUSIONS OF LAW OF
THE CALIFORNIA PUBLIC UTILITIES COMMISSION**

**To: The Honorable David H. Coffman
Presiding Administrative Law Judge**

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March 15, 2018

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PUBLIC VERSION – CUI/PRIV PORTIONS REDACTED

**INITIAL BRIEF AND PROPOSED FINDINGS OF FACT AND CONCLUSIONS
OF LAW
OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION**

**To: The Honorable David H. Coffman
Presiding Administrative Law Judge**

Pursuant to Rule 706 of the Commission’s Rules of Practice and Procedure, and the March 31, 2017 Order Establishing Procedural Schedule in this case, the California Public Utilities Commission (“CPUC”) submits this Initial Brief and Proposed Findings of Fact and Conclusions of Law.¹

STATEMENT OF THE CASE

The CPUC incorporates and accepts the Joint Statement of Procedural History and Joint Statement of Stipulated Facts previously submitted in this proceeding. The CPUC presents the testimony of one witness: Geneva Looker, Ex. PUC-0001. The CPUC testimony and Initial brief demonstrate that PG&E’s capital additions forecast in not just and reasonable and that PG&E has incurred over \$500 million in imprudent capital additions expenses which justify disallowances to reach a just and reasonable transmission revenue requirement.

SUMMARY OF ARGUMENT

Over 1½ years ago, on July 29, 2016, Pacific Gas and Electric Company (“PG&E”) filed its eighteenth Transmission Owner rate case (“TO18”) with this

¹ The CPUC reserves the right to address in its Reply Brief any issue that it does not address in this Initial Brief.

PUBLIC VERSION – CUI/PRIV PORTIONS REDACTED

Commission seeking a \$1.718 billion retail transmission revenue requirement (“TRR”) to be effective on October 1, 2016, with a nominal suspension period.²

This TO18 rate case is unprecedented in several ways. PG&E has one of the largest TRRs of any investor-owned public utility in the United States, representing one of the largest TO rate cases reviewed by FERC. In addition, PG&E’s TO18 filing seeks a \$387 million increase over its settled TRR in its TO17 case. In other words, PG&E’s seeks a 29% increase in its 2017 TRR over its 2016 TRR.

That this case went to hearing is also unprecedented. While litigation occurred to resolve discrete issues in PG&E’s TO rate cases before 2000, the parties – many of the same ones here – have settled more than a dozen TRR requests since that time.

PG&E’s growing revenue requirement, with no significant capacity additions, and no end in sight,³ have driven PG&E’s largest transmission customers to advocate together for a significant readjustment to PG&E’s revenue requirement.

PG&E’s retail TRR (as settled in TO17) has increased 356% since the \$292 million TRR settled in its first TO case.⁴ While significant TRR increases are expected when a utility is constructing large new transmission lines that expand the capacity of its system – this does not explain PG&E’s TRR increases. It appears that the bulk of PG&E’s capital

² PG&E TO18 Application, FERC Docket No. ER16-2320, Ex. PGE-0001at 2.

³ Ex. PGE-0038 at 7:7-8, Gabbard Rebuttal (“PG&E expect that replacement-related capital work will continue to grow as PG&E’s assets continue to age.”); and *id.* at 7:16-18 (“capital investment will shift significantly, from capacity increase-related projects, to lifecycle replacement projects.”).

⁴ Ex. PUC-0001 at 9, Table C, Looker Direct.

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additions investments have been made to repair or replace existing assets.⁵ Given the significant amounts being invested in this work – more than \$802 and \$696 million in capital expenditures for 2016 and 2017 respectively⁶ – it is appropriate to ask whether the work is truly needed, or whether it unjustly and unreasonably burdens ratepayers with unnecessary costs.

This question is nearly impossible to answer because nearly all of this investment has been made without any review of those projects by any third party – not FERC, not the CAISO, and not the CPUC.⁷ PG&E’s “self-approved” projects comprise \$831.5 million (or 63%) of the capital additions proposed to be ratebased in 2016 and \$612 million (or 81%) in 2017. In comparison, the capital additions for CAISO-approved projects – which are capacity projects by definition – represent \$493 million (or 37%) of the capital additions proposed to be ratebased in 2016 and \$147 million (or 19%) in 2017.⁸

PG&E’s lack of new capacity and the amount spent on its “self-approved” repair and replacement activities have led the CPUC to question PG&E’s electric transmission repair and replacement practices. This review has been informed by the CPUC’s investigations into the root causes of the 2010 San Bruno explosion of a PG&E high

⁵ Ex. PUC-0001 a 36, Table K, Looker Direct.

⁶ Ex. PGE-0009, Table PGE-9-1, Totals less MWCs 60, 61 and 82.

⁷ See Section V.B.2 below and *CPUC, et al. v. PG&E*, FERC Docket No. EL17-45 for information regarding PG&E’s “self-approval” process.

⁸ Ex. PGE-0028 at 61-75.

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pressure gas transmission line. The CPUC found in those investigations, among other things, that PG&E mismanaged the repair and replacement of its gas transmission system for decades by engaging in poor recordkeeping practices that prevented it from properly identifying the assets that most needed the work.⁹

The ratepayers represented by the CPUC in this case will pay approximately 90% of the total TRR approved by FERC in this proceeding – which totals \$1.546 billion of PG&E’s current request. As outlined in Section V.A below, the evidence in this case shows similar mismanagement of PG&E’s electric transmission assets. This evidence demonstrates that PG&E does not, and cannot, engage in a functional data-driven condition-based methodology to identify, rank, and pursue the most needed electric transmission projects for repair and replacement.

In addition, PG&E’s own testimony explains that PG&E now engages in a practice of “advancing” projects not forecasted to go into ratebase in order to ensure PG&E meets its annual capital additions budget target.¹⁰ As described in Section V.A.2 below,, advanced projects in this rate case total over \$303 million in capital additions in this rate case, with \$265 million of those capital additions not even identified in the TO18 application.

⁹ See e.g., CPUC Decision 15-04-021, *Modified Presiding Officer’s Decision Regarding Allegations Of Violations Regarding Pacific Gas And Electric Company’s Operations And Practices With Respect To Facilities Records For Its Natural Gas Transmission System Pipelines* (April 9, 2015) I.11-02-016, 2015 WL 1687668.

¹⁰ Ex. PGE-0043 at 5:13-22, Vijayraghavan Rebuttal.

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The CPUC is also challenging the prudence of two aspects of PG&E's expenditures which contribute significantly to ratebase in this case. Those include over \$90 million in cost-overruns associated with the Embarcadero-Potrero transmission project and PG&E's historic and on-going investment in self-approved transmission projects in violation of this Commission's Order 890.

All of the evidence shows that for PG&E, it doesn't really matter what transmission capital investments get made, whether capital projects are prudently identified, ranked and pursued, or whether ratepayers will be paying only just and reasonable rates for safe and reliable electric service. PG&E's only concern in that money gets spent and assets are placed in rate base in a predictable manner to ensure its cash flow and return to shareholders.

For all of these reasons, and others set forth below, PG&E's capital additions forecast was not reasonable when made because it is based on proposed projects that cannot be shown to be needed and PG&E's TRR is not just and reasonable because it reflects the impact of more than \$500 million in imprudent investments. A significant adjustment is necessary to force PG&E to determine capital additions priorities and track its progress in meeting those priorities in a meaningful and cost effective manner so the most necessary projects are pursued in the right priority and at the right price.

The CPUC proposes the following specific adjustments herein:

- A \$73 million reduction to PG&E's proposed 2017 TRR to address PG&E's unjust and unreasonable practice of self-approving more than 60% of its capital additions;

PUBLIC VERSION – CUI/PRIV PORTIONS REDACTED

- A \$475 million reduction in PG&E's ratebase as depreciated going forward to address PG&E's unjust and unreasonable practice of self-approving more than 60% of its capital additions;
- A \$14.8 million reduction in PG&E's 2017 TRR to address PG&E's imprudently incurred cost overruns on the Embarcadero-Potrero project; and
- A \$91.3 million reduction in PG&E's ratebase as depreciated going forward to address PG&E's imprudently incurred cost overruns on the Embarcadero-Potrero project.¹¹

ARGUMENT

I. RATE OF RETURN ON EQUITY (ROE)

The CPUC elects not to address this issue at this time.

II. COST OF LONG-TERM DEBT

The CPUC elects not to address this issue at this time.

III. CAPITAL STRUCTURE

The CPUC elects not to address this issue at this time.

IV. DEPRECIATION

The CPUC elects not to address this issue at this time.

¹¹ Ex. PUC-0001 at 28:25-29:8, Looker Direct.

PUBLIC VERSION – CUI/PRIV PORTIONS REDACTED

V. CAPITAL ADDITIONS

A. Whether PG&E’s Capital Additions Forecast Is Just And Reasonable

PG&E’s capital additions forecast is not just and reasonable because, as described in Sections V.A.1 and V.A.8 below, it is expressly designed to result in spending more on capital additions than is reasonably necessary to maintain the reliability and safety of the system. This spending is reflected in PG&E’s TRR, which is growing at a rapid rate. The cost of capital additions (in return on equity) comprises approximately 32% of PG&E’s requested TRR in this rate case.

“At the onset of the CAISO’s formation in 1997, PG&E’s wholesale TRR was set at \$292 million. Twenty years later, PG&E is requesting a wholesale TRR of \$1.706 billion.”¹² PG&E has been investing heavily in transmission assets, but “has little to show in the way of new transmission assets that provide additional capacity for the over \$11.5 billion ... paid by its customers during the last twenty years.”¹³

FERC Form 1 filings between 2007 and 2016 show \$6.2 billion invested in transmission capital additions over the last ten years. However, during that time, PG&E has built no new transmission substations,¹⁴ and since 2012, PG&E’s total miles of

¹² Ex. PUC-0001 at 6:12-14 and 7:1-2, Looker Direct.

¹³ Ex. PUC-0001 at 10:13-17 and 9:1-2, Looker Direct.

¹⁴ Ex. PUC-0008 at 1, Answer (a), CPUC-PGE-157, 6/1/17.

PUBLIC VERSION – CUI/PRIV PORTIONS REDACTED

transmission lines have decreased by approximately 300 miles.¹⁵ This lack of capacity additions is not surprising, as the loads in PG&E's territory have been trending downward, particularly in the last few years.¹⁶

It appears that much of PG&E's new investment is to replace or upgrade facilities.¹⁷ While the CPUC recognizes that repair and replacement are necessary components of a utility's operation, the amount that PG&E has been spending on what appears primarily to be replacement of transmission facilities is staggering and potentially unjustified. Further, the identification and development of these projects is done exclusively by PG&E – there is no regulatory or other third party reviewing PG&E's determination that these projects are needed.¹⁸ Thus, there is reason to be concerned that PG&E is “gold plating” the system.

Also concerning is that there is no end in sight. PG&E's future forecasts show that the rapid rise in TRR is likely to continue unless PG&E is held to account for the choices it is making in its capital additions. PG&E forecasts more than [REDACTED] on transmission capital expenditures from 2018 to 2021.¹⁹

¹⁵ Ex. PUC-0001 at 17:16-17, Looker Direct.

¹⁶ Ex. PUC-0001 at 17:10-12, Looker Direct.

¹⁷ Ex. PUC-0001 at 20:6-7, Looker Direct.

¹⁸ Ex. PUC-0001 at 20:9-14, Looker Direct.

¹⁹ Ex. TNC-0185 (PRIV) at 36 and 53, Electric T&D S2 Executive Discussion, 11/3-4/2016, CPUC-PGE179Atch05PRIV .

PUBLIC VERSION – CUI/PRIV PORTIONS REDACTED

The TRR increases from such investments, compounded by declining loads, cannot be sustained in light California’s other legislatively mandated energy priorities, including its Renewables Portfolio Standard (“RPS”),²⁰ energy efficiency,²¹ and electrification of transportation²² - all of which include costs recoverable from ratepayers. All of these programs emphasize the need for cost-effective solutions and require CPUC oversight to ensure reasonableness.²³ For example, the RPS statute requires “[a] process that provides criteria for the rank ordering and selection of least-cost and best-fit eligible renewable energy resources to comply with the California Renewables Portfolio Standard Program obligations on a total cost and best-fit basis.”²⁴ The transportation electrification statute similarly requires that “[p]rograms proposed by electrical corporations shall seek to minimize overall costs and maximize overall benefits.”²⁵

It is time for PG&E’s transmission investment to be held to a similar standard, and for PG&E to be accountable for the imprudent expenditures it has incurred and the unjust and unreasonable transmission planning practices it has employed for at least a decade.

²⁰ Cal. Pub. Util. Code § 399.11 (requiring an RPS of 33% by 2020 and 50% by 2030).

²¹ Cal. Pub. Util. Code § 381.2 (energy efficiency).

²² Cal. Pub. Util. Code § 740.12 (transportation electrification).

²³ Cal. Pub. Util. Code § 399.11(e)(1) (“the commission shall ensure rates are just and reasonable, and are not significantly affected by the procurement requirements of this article.”); Cal. Pub. Util. Code § 381.2(b) (“Electrical corporations and gas corporations shall be permitted to recover in rates the reasonable costs of these programs.”); and Cal. Pub. Util. Code § 740.12(b) (“The commission shall approve, or modify and approve, programs and investments in transportation electrification, including those that deploy charging infrastructure, via a reasonable cost recovery mechanism.”).

²⁴ Cal. Pub. Util. Code § 399.13(a)(4)(A) (renewable energy procurement).

²⁵ Cal. Pub. Util. Code § 740.12(c) (transportation electrification).

EXHIBIT B

PACIFIC GAS AND ELECTRIC COMPANY
EXHIBIT PGE-0003
TRANSMISSION RISK MANAGEMENT AND
PROJECT MANAGEMENT IMPROVEMENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company)

Docket No. ER19-____-000

Summary of the Prepared Direct Testimony
of David P. Gabbard

Mr. Gabbard's testimony (Exhibit No. PGE-0003) describes PG&E's risk management programs and how these programs inform PG&E's investment in electric transmission projects in 2018 and 2019. He explains PG&E's process and the tools used to identify risk drivers, controls, and mitigation options. Mr. Gabbard goes on to define each of PG&E's top risks. He describes how PG&E seeks to mitigate its top risks, including risks associated with wildfires, failure of a substation, overhead conductors, and other transmission-related risks. He also explains how PG&E's risk assessments help prioritize PG&E's capital investments in transmission infrastructure. Finally, Mr. Gabbard describes PG&E's project management process and, specifically, improvements that PG&E has made to its project management process.

1 additional insulator replacement. Replacing additional conductors
2 and insulators reduces the likelihood that those conductors and
3 insulators will fail, therefore reducing the likelihood that those failures
4 will lead to transmission wires down.

5 The third mitigation is additional ROW expansion. This mitigation
6 represents work to expand the vegetation ROW corridors around
7 transmission lines which have historically experienced large numbers
8 of vegetation related outages. Expanding vegetation ROWs on these
9 lines reduces the likelihood that they will fail and cause wires down
10 due to contact with vegetation.

11 The fourth mitigation is additional public awareness outreach.
12 This mitigation involves sending bill inserts to customers to inform
13 them of the dangers of energized conductors, and to warn them not
14 to climb electrical structures such as transmission towers. This
15 mitigation is designed to reduce the likelihood of third-party contact
16 with intact transmission overhead conductor.

17 4. Other Transmission Risk Reduction Work

18 Q 29 What other work is PG&E doing to reduce transmission risk?

19 A 29 PG&E is implementing other programs to reduce general
20 transmission risk. These programs include the Transmission Line
21 SCADA Switch Program and the Tower Replacement Program.

22 Q 30 Describe the Transmission Line SCADA Switch Program and how
23 that will address the Transmission Risk.

24 A 30 The Transmission Line SCADA Switch Program is established to
25 reduce the outage duration for customers served by various
26 substations by providing remote restoration or de-energization
27 capability on targeted transmission lines. This program is to install
28 Transmission Line SCADA switches at existing and new locations to
29 improve customer and grid reliability by providing capability and
30 access to/from control centers to operate the installed switches and
31 improve electric grid reliability and system operation under normal
32 and emergency operating conditions.

1 Q 31 Describe the Tower Replacement Program and how that will address
2 the Transmission Risk.

3 A 31 The Tower Replacement Program is established to manage the
4 replacement of steel structures that have reached the end of their
5 useful lives. The program targets replacement of deteriorated
6 structures where repair is either less cost effective or not feasible.

7 **D. PG&E's Project Management Improvements**

8 Q 32 Please explain the project management improvements that have
9 been made by PG&E.

10 A 32 PG&E has undertaken major improvements to its project
11 management processes over the past few years, which have resulted
12 in recent forecasts being much closer to the actual capital additions
13 achieved in those forecast periods.

14 In 2012, PG&E re-structured its ET organization, in part to
15 improve the performance of its project management processes.
16 As part of this re-structuring, PG&E created a centralized work and
17 resource management group to provide project management
18 oversight and governance.

19 This group undertook several initiatives to improve project
20 management performance. Changes resulting from some of these
21 initiatives include:

- 22 • The creation of an integrated planning calendar, combining all
23 external (e.g., TO filings) and internal work planning initiatives to
24 ensure that inputs are consistent across all of those initiatives;
- 25 • The creation of the ET Capital Investment and Execution (CIE)
26 Planning Process;
- 27 • A shift from a single year to a five-year planning horizon.
28 A longer-term planning horizon improves visibility into the
29 upstream impacts of long-term project operational dates,
30 improving PG&E's ability to limit volatility in project plans and
31 reduce costs by allowing PG&E to make, and follow, multi-year
32 contract commitments with suppliers; and

- 1 • The adoption of the forecasting guidelines established by the
2 Association for the Advancement of Cost Engineering (AACE)
3 International.

4 Q 33 How does PG&E optimize the execution of its transmission
5 investments?

6 A 33 PG&E develops a five-year plan that includes a portfolio of work
7 necessary to safely and reliably operate its transmission system.
8 PG&E leverages this longer-term view to manage demand on
9 construction and engineering resources. This multi-year work plan
10 allows PG&E to optimize the utilization of limited resources and
11 minimize impact of project level volatility.

12 Q 34 From time-to-time, does PG&E advance projects within its
13 five-year plan?

14 A 34 Yes. PG&E views the ability to more efficiently execute a broader
15 book of work on behalf of its customers as an obligation. It is the
16 intent of PG&E's ET leadership to perform as much of the work in its
17 five-year plan at as low a cost as possible in order to maximize the
18 value created for its customers. PG&E balances and stabilizes its
19 five-year plan by identifying work that may be accelerated or deferred
20 in order to achieve operational efficiencies across its transmission
21 portfolio.

22 This advancement process may be employed when a project
23 PG&E planned to implement could not be implemented for some
24 reason. Given the scale and scope of PG&E's service area, there are
25 a variety of reasons that might impact the schedule for a transmission
26 project that is planned for the current year, including, but not limited
27 to emergency replacements, clearance availability, permit approval,
28 reassignment of resources, and identification of new Work at the
29 Request of Others.

30 Active decisions to accelerate or defer work can help mitigate the
31 impact of these project delays that are outside of PG&E's control and
32 keep resource utilization maximized as well as clearance utilization

EXHIBIT C

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Pacific Gas and Electric Company) **Docket ER16-2320-002**

PREPARED REBUTTAL TESTIMONY OF

DAVID P. GABBARD

EXHIBIT NO. PGE-0038

October 9, 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company)

Docket No. ER16-2320-002

Summary of the Prepared Rebuttal Testimony
of David P. Gabbard

Mr. Gabbard's rebuttal testimony (Exhibit No. PGE-0038) presents PG&E's rebuttal to issues raised in the testimony of Ms. Geneva G. Looker on behalf the California Public Utilities Commission (CPUC), Mr. David B. Cohen on behalf of the Transmission Agency of Northern California , Mr. Robert C. Smith on behalf of the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California, regarding the reasonableness of PG&E's investment in transmission assets.

Mr. Gabbard specifically rebuts the assertion that PG&E has historically over-forecasted its capital additions in past Transmission Owner Tariff rate filings. He explains that: PG&E's growth in transmission revenue requirement is consistent with that of the other California investor-owned utilities; PG&E's investments in its existing system are both justified and cost-effective; a comparison of recent forecasts with actual capital additions demonstrates that PG&E's capital additions forecast made in this proceeding can be relied upon by the Commission as being reasonable when made; and cost variances associated with the Embarcadero-Potrero Cable Project, which is discussed in the testimony of Ms. Geneva Looker, were consistent with industry accepted ranges, and PG&E's spending on that project was prudent. Finally, Mr. Gabbard recommends that the Federal Energy Regulatory Commission (FERC) should not defer to the CPUC in making transmission ratemaking decisions governing facilities that are FERC jurisdictional.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Pacific Gas and Electric Company) **Docket ER16-2320-002**

PACIFIC GAS AND ELECTRIC COMPANY
EXHIBIT NO. PGE-0038

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 Rate Base Because the Actual Costs of the
 Embarcadero-Potrero Cable Project Were Greater Than the
 Cost Included in the CPUC’s CPCN Approval for the Project. 12

GLOSSARY OF ACRONYMS

| | |
|--------------------------------|--|
| AACE: | Association for the Advancement of Cost Engineering |
| CAISO: | California Independent System Operator Corporation |
| CPCN: | Certificate of Public Convenience and Necessity |
| CPUC: | California Public Utilities Commission |
| FERC or Commission: | Federal Energy Regulatory Commission |
| IOUs: | Investor-Owned Utilities |
| ORA: | Office of Ratepayers Advocates |
| Parties: | CPUC, TANC, Six Cities, and Trial Staff |
| PG&E: | Pacific Gas and Electric Company |
| ROW: | Right-of-Way |
| SCE: | Southern California Edison Company |
| SDG&E: | San Diego Gas & Electric Company |
| Six Cities: | California Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside |
| TANC: | Transmission Agency of Northern California |
| TO: | Transmission Owner |
| TO18: | PG&E's Eighteenth Transmission Owner Rate Case |
| TPP: | Transmission Planning Process |
| Trial Staff: | FERC Trial Staff |
| TRR: | Transmission Revenue Requirement |

TABLE PGE-0038-2
RATE OF GROWTH IN TRR BETWEEN 2007 AND 2017

| Line No. | IOU | 2007 Base TRR ^(b) | 2017 Base TRR ^(a) | Percent increase in TRR between 2007 and 2017 |
|----------|-------|------------------------------|------------------------------|---|
| 1 | PG&E | \$595 | \$1,705 | 187% |
| 2 | SCE | \$308 | \$1,182 | 284% |
| 3 | SDG&E | \$180 | \$701 | 289% |

(a) CAISO 15Sep17 TAC Rates Worksheet (Attachment PGE-0038-2).

(b) CAISO 01Jan07 TAC Rates Worksheet (Attachment PGE-0038-3).

1 Q 9 What do you conclude from the above analysis?

2 A 9 The assertion that PG&E's growth in TRR exceeds that of the other
3 California IOUs is based on an incomplete and misleading
4 comparison and is incorrect. When TRR is put in the context of
5 system size and the rate of increase over time, PG&E's investment in
6 transmission is growing at a slower pace than the other two California
7 IOUs.

8 **2. PG&E's Investments in its Existing Footprint Are Justified, Cost**
9 **Effective, and Necessary to Maintain the Safety and Reliability of**
10 **PG&E's Transmission Service to its Customers**

11 Q 10 Do you agree with CPUC witness Ms. Looker's and TANC witness
12 Mr. Cohen's assertions that PG&E's TRR is not just and reasonable
13 because the overall number of circuit miles of transmission line and
14 number of new transmission substations in its service area has not
15 increased significantly?

16 A 10 No. Ms. Looker and Mr. Cohen are not correct in linking changes in
17 overall line mileage or substation counts to the justness and
18 reasonableness of PG&E's investment in electric transmission.
19 As Ms. Looker correctly notes in her testimony,¹ repair and
20 replacement are necessary components of a utility's operations.
21 In fact, capital improvements to and replacement of existing

¹ Exhibit No. PUC-0001, page 20, lines 9-10.

1 electric transmission infrastructure are an essential part of good
2 utility operations.

3 PG&E must repair or replace assets that are approaching the end
4 of their service lives, that are deteriorating, or that have failed.
5 Replacement and repair of PG&E's assets are essential to
6 maintaining and improving PG&E's transmission service to its
7 customers. PG&E expects that replacement-related capital work will
8 continue to grow as PG&E's assets continue to age. A significant
9 part of PG&E's transmission infrastructure was constructed in the
10 years following World War II, with some assets being even older.
11 In addition, PG&E has one of the largest investor-owned fleet of
12 hydroelectric facilities in the Country. By and large, these facilities
13 are located remotely from PG&E's load centers. Many of these
14 facilities—and their related transmission assets—were constructed in
15 the early 1900s. Due to an increasingly large number of these assets
16 nearing the end of their useful service lives, capital investment will
17 shift significantly, from capacity increase-related projects, to lifecycle
18 replacement projects.

19 Q 11 Is the practice of attempting to make capital additions within existing
20 Rights-of-Way (ROW) consistent with industry principles?

21 A 11 Absolutely. In fact, this practice is affirmed by California Senate
22 Bill 2431 (Chapter 1457 of the Statutes of 1988). In that bill, the
23 California state legislature declared that:

24 ...the construction of new high-voltage transmission lines within
25 new rights-of-way may impose financial hardships and adverse
26 environmental impacts on the state and its residents.

27 As a result, the bill established principles for effective long-term
28 transmission corridor planning, commonly known as the "Garamendi
29 Principles." The first of the Garamendi Principles encourages:

30 ...the use of existing rights-of-way by upgrading existing
31 transmission facilities where technically and economically
32 justifiable.

33 Through these principles, the state has recognized that
34 construction in existing ROWs can have environmental and financial

1 benefits over construction in new ROWs. This state legislation
2 supports the fact that PG&E has not added significant “new”
3 transmission lines in new ROWs, and has not built a significant
4 number of “new” transmission substations. Instead, PG&E is
5 focusing on replacing aging infrastructure in existing ROWs, and on
6 existing PG&E property and, where appropriate, increasing capacity
7 through those replacements.

8 **3. PG&E’s Capital Additions Forecast is Reasonable**

9 Q 12 Do you agree with Ms. Looker’s, Mr. Cohen’s, Mr. Smith’s,
10 and Mr. Hoffman’s testimony that PG&E’s TRR in TO18 should
11 be reduced because PG&E has historically over-forecasted its capital
12 additions?

13 A 12 No. As I explain below, these proposed reductions are not
14 well-supported and are inappropriate. In addition, PG&E has
15 undertaken major improvements to its project management
16 processes over the past few years, which have resulted in recent
17 forecasts being much closer to the actual capital additions achieved
18 in those forecast periods. There should be no reduction because,
19 as a result of these process improvements, PG&E expects the
20 2016-2017 forecasts contained in the TO18 filing to be very close to
21 what PG&E actually makes in capital additions over that period.

22 Q 13 Please explain the project management improvements that have
23 been made by PG&E.

24 A 13 In 2012, PG&E re-structured its electric transmission organization,
25 in part to improve the performance of its project management
26 processes. As part of this re-structuring, PG&E created a centralized
27 work and resource management group to provide project
28 management oversight and governance.

29 This group undertook several initiatives to improve project
30 management performance. Changes resulting from some of these
31 initiatives include:

- 1 • The creation of an integrated planning calendar, combining all
- 2 external (e.g., TO filing) and internal work planning initiatives to
- 3 ensure that inputs are consistent across all of those initiatives;
- 4 • The creation of a uniform project development scoping process,
- 5 bringing more consistency and governance to project
- 6 management. The process includes requirements to use
- 7 standardized templates and checklists for project scope
- 8 development, and a review process to assess the soundness of
- 9 project scopes;
- 10 • A shift from a single-year to a 5-year planning horizon. A longer
- 11 term planning horizon improves visibility into the upstream
- 12 impacts of long-term project operational dates, improving PG&E's
- 13 ability to limit volatility in project plans and reduce costs by
- 14 allowing PG&E to make, and follow, multi-year contract
- 15 commitments with suppliers;
- 16 • The creation of an integrated change control process.
- 17 The process introduced a consistent method for requesting,
- 18 reviewing, and approving changes to projects; and
- 19 • The creation of an executable work plan framework. This
- 20 framework includes a process to review projects and project
- 21 schedules prior to execution to ensure that they can truly be
- 22 executed given real world constraints. The framework includes
- 23 executability, readiness, and resource balance metrics to
- 24 measure performance.

25 Q 14 What were the results of these project management improvements?

26 A 14 Actual capital addition amounts are now very close to the forecasted
27 amounts contained in PG&E's TO Tariff rate case filings. This fact
28 can be illustrated by examining the data shown in Table PGE-0038-3
29 below, which compares PG&E's forecasted gross capital additions to
30 actual gross capital additions for the years 2011-2016. The data
31 show significant decreases in variances between forecasted and
32 actual capital additions after 2013, once some of the project
33 management improvement initiatives described in the preceding Q&A

EXHIBIT D

3

4 - - - - - x

5 IN THE MATTER OF: : Docket Number
6 PACIFIC GAS & ELECTRIC COMPANY : ER16-2320-002

7 - - - - -x

Hearing Room 5
Federal Energy Regulatory
Commission
888 First Street, NE
Washington, DC

15 Tuesday, January 23, 2018

17 The above-entitled matter came on for hearing, pursuant
18 to notice, at 10:04 a.m.

20 BEFORE:

21 HONORABLE DAVID H. COFFMAN
22 ADMINISTRATIVE LAW JUDGE

23
24
25 APPEARANCES (HERETOFORE NOTED.)

1 P R O C E E D I N G S

2 PRESIDING JUDGE: Let's go on the record.

3 Ms. Bone.

4 Whereupon,

5 DAVID GABBARD

6 resumed the stand and, having been previously duly sworn,

7 was examined and testified further as follows:

8 CROSS-EXAMINATION (Continued)

9 BY MS. BONE:

10 Q Good morning, Mr. Gabbard. Traci Bone from the
11 California Public Utilities Commission.

12 You testify that PG&E must repair or replace
13 assets that are approaching the end of their service lives
14 that are deteriorating or that have failed; is that
15 correct?

16 A Yes, that is correct.

17 Q And you also testify that a significant part of
18 PG&E's transmission infrastructure was constructed in the
19 years following World War II, with some assets being even
20 older; is that correct?

21 A Yes.

22 Q And what years are you talking about when you
23 make that statement?

24 A Can you please clarify the question?

25 Q Yes. What years are you talking about when you

1 say that PG&E's -- a significant part of PG&E's
2 transmission infrastructure was constructed in the years
3 following World War II?

4 A Referencing a broad era of time in the '50s and
5 '60s. That's referencing a large portion of our assets,
6 but we have a significant portion of our 115 kV assets that
7 were built as early as in the 1920s time frame and earlier.

8 Q This is what I described in your deposition as
9 the pig and the python problem. There were a lot of assets
10 built at the same time during this World War II period, in
11 the '50s and '60s and that these assets will potentially
12 need to be replaced around the same time. Is that an
13 accurate description of the problem?

14 A Yes.

15 Q Do you know if Edison and SDG&E are facing the
16 same challenge?

17 A I do not.

18 Q Do you know if any other utilities outside of
19 California are facing a similar challenge?

20 A In general, this challenge exists across the
21 utility sector.

22 Q Do you know the average age of PG&E's
23 transmission system assets?

24 A I do not.

25 MS. BONE: If we could have a moment to go off

1 the record?

2 PRESIDING JUDGE: Yes, Ms. Bone.

3 (Discussion off the record.)

4 PRESIDING JUDGE: Let's go back on the record.

5 BY MS. BONE:

6 Q The CPUC agrees with you that PG&E has a
7 significantly larger system both in footprint and circuit
8 miles than Edison and SDG&E. We also agree that Edison and
9 SDG&E TRRs are growing faster than PG&E's. What we're
10 curious about is in your analysis, comparing these two
11 utilities, did you know the reasons for these utilities'
12 TRR growth when you submitted your rebuttal testimony?

13 A No, I do not know the details of the makeup of
14 all projects that represent the rate base that contributes
15 to Edison's or San Diego's transmission revenue
16 requirement. I did not imply that I did, but I did use the
17 total revenue requirement as a reference point to highlight
18 that PG&E's rate of increase as well as the absolute
19 revenue requirement per line mile were less than each of
20 the other two California utilities.

21 Q Mr. Gabbard, I take it that you did not know how
22 much -- that you do not know how much Edison and SDG&E are
23 spending on repairing and replacing their current assets?

24 A I do not.

25 Q Do you know if Edison and SDG&E's spending on

1 repairing and replacing the current assets is commensurate
2 with PG&E's spending on those same assets on a relative
3 basis, for example, on a circuit mile basis?

4 A I do not.

5 Q Mr. Gabbard, who prepared this argument for you
6 that compared Edison and SDG&E's TRRs to the PG&E TRR, the
7 argument that's in your rebuttal testimony?

8 A The coordination of the argument was prepared by
9 Kenneth How.

10 (Exhibit PUC-0050 identified.)

11 BY MS. BONE:

12 Q Let's go back to the issue of your knowledge of
13 the average age of PG&E's transmission assets. The
14 California Public Utilities Commission legal division
15 issued a data request to PG&E and one of the issues that it
16 addressed -- that PG&E addressed in response was the
17 average age of its facilities. This is marked as Exhibit
18 PUC-0050.

19 Ms. Looker, if you could put that on the screen.

20 Is it on your screen yet, Mr. Gabbard?

21 A It is.

22 Q As Ms. Looker was scrolling through, is this a
23 document that you're familiar with?

24 A Yes, it is.

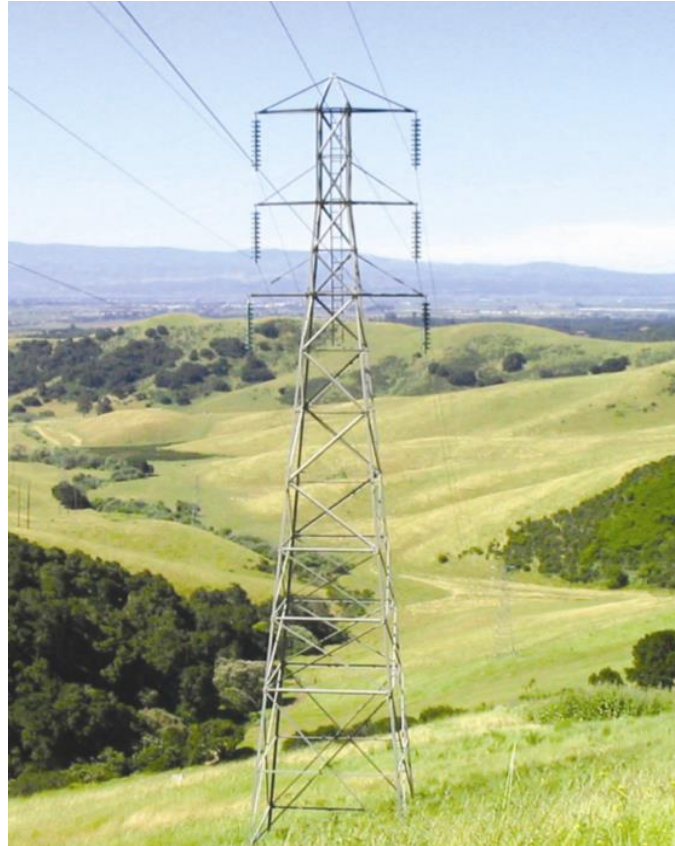
25 Q Did you review it before it was issued to the

EXHIBIT E



Electric Transmission Overhead Steel Structure Strategy Overview

Version 1.0



June 2017
By: Feven Mihretu,
Transmission Asset Strategy



Contents

Asset Base

Asset Performance & Health

Asset Capital Investment Plan

Asset Prioritization Criteria



Transmission Line Steel Structure Strategy

The Transmission Line Steel Structure strategy will manage the asset life cycle (e.g. Create, Utilize, Maintain, Renew (replace), and Dispose) based on risk. The renew asset life cycle is based on proactive cost replacements for high risk assets. For medium risk assets, it is based on reactive replacements following asset failures.

Asset failure analysis will be performed to identify specific, endemic failure trends. Transmission Steel Structure has a high level of risk and therefore, creates the need to renew, based on life expectancy. Some of the major objectives associated with Steel Structures are:

Safety:

Eliminate significant public and employee safety hazards from Steel Structure failures.

Reliability:

Achieve second quartile T&D reliability performance by reducing in-service failures

Environmental:

Ensure the environment is protected from structure failure resulting conductor on ground causing fire.



Steel Structure Strategy Plan

Short Term (2017)

- ✓ Continue to evaluate field input and repair/replace as needed.
- ✓ Continue to coordinate/bundle asset replacement with reliability strategy and system operations. Also integrate with other programs such as Maintenance, Operations, NERC Alert, Capacity, WRO, etc.
- ✓ Complete assessments and develop plan to repair and/or replace towers in Bay Water, Delta Water and Salt pond towers.
- ✓ Develop a steel structure replacement plan
- ✓ Re-assess circuit and asset risk including identification and mitigations
- ✓ Develop a corrosion management plan for new and existing foundations.
- ✓ Evaluate the effectiveness of the design, maintenance and inspection program and make necessary recommendations for improvement
- ✓ Evaluate existing climbing guard program and make appropriate adjustments as needed
- ✓ Develop a Data Management Plan which includes data quality validation, proper warehousing in GIS, and an asset inventory process utilizing maintenance and inspections
- ✓ Evaluate Mean and Maximum Asset Life Expectancy from other data sources
- ✓ Develop and facilitate an annualized 5 year investment plan

Long Term (2018)

- ✓ Develop a corrosion standard/procedure for corrosion management of new and existing foundations
- ✓ Develop a structure prioritization criteria and replacement program that includes risk, asset type and performance, asset life cycle, asset obsolescence, operational flexibility, and optimum replacement approach.
- ✓ Develop a system wide asset risk in a visual and tabular format



Contents

Asset Base

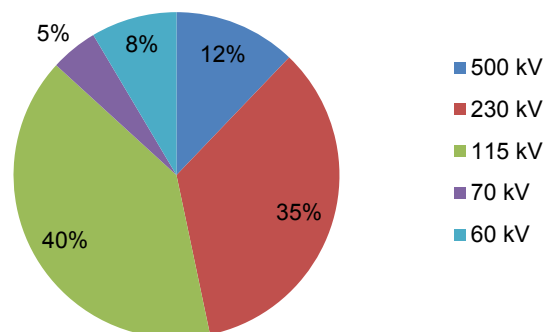


Asset Base – Steel Structures In Service as of December 2016

- 149,000 transmission overhead structures - steel, wood, concrete, fiberglass and Hybrid
- 47,000 steel transmission overhead structures
 - Lattice steel towers/poles: 83% or 39,254 structures with over 150 different types
 - Light duty steel poles: 10% or 4,487
 - Tubular steel poles: 7% or 3,370

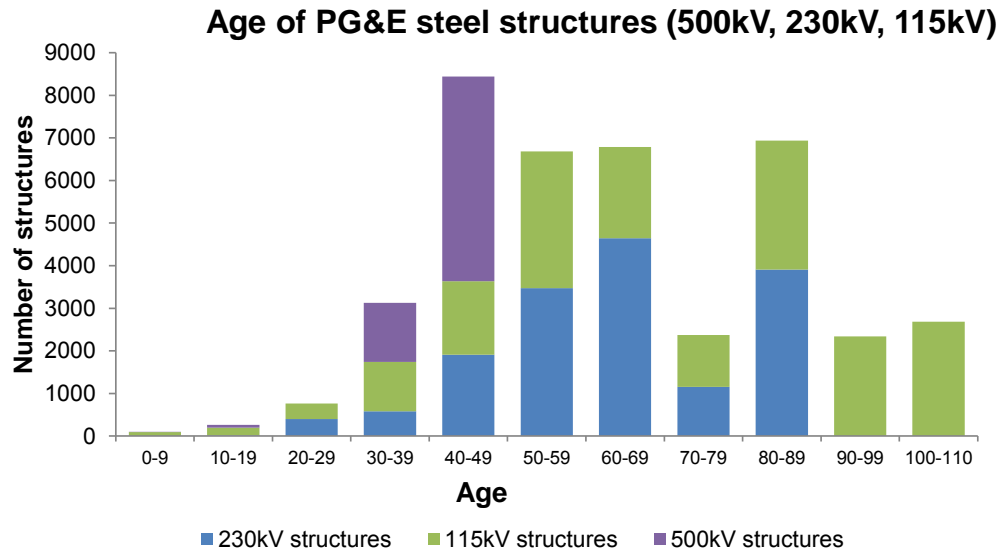
| Voltage | Structure Count |
|---------|-----------------|
| 500 kV | 5,700 |
| 230 kV | 16,200 |
| 115 kV | 18,800 |
| 70 kV | 2,200 |
| 60 kV | 4,000 |

Structure Count





Asset Base – Steel Structure In Service



- Oldest structures are 108 years old, average age is 68
- Mean Life Expectancy is 65 years
 - Max Coastal: 80 years
 - Max Valley: 100+ years
- Poor age data on 60 and 70 kV structures
- Structures age data/life expectancy is from a year 2010 Quanta Technology Study



Contents

Asset Performance & Health



Asset Performance & Health – Steel Structures Performance

❖ Over 6 years (2011-2016) outage history, one tower failure

- In 2015 Tower 61/268 collapsed (tower 61/267 also failed as a result of 61/268 failing) at Moss Landing Power Plant (MLPP) that carried Moss Landing-Metcalf #1 & #2-230kV lines.
 - WPE (Footing set improperly at installation)
 - Major Event Day (MED)

❖ Over 6 years (2011-2016), out of 67 LC notifications (under Mat Code 70S)

- 63 have been identified based on a wide array of issue, but not limited to:
 - Anchor replacement
 - Conductor Clearance
 - Raise / Stabilize tower
 - Foundation Repair – Soil movement (Direct buried / concrete footing), Buckled/Bent leg members

❖ Bay Water Inspection (2015-2016)*

- Non-destructive visual inspection of approximately 500 towers located in the San Francisco bay are.
 - Nine towers that were rated a five (5) that would require repairs very soon – Completed
 - Twenty towers were rated a four (4) that require repairs in the near future.
 - Ninety-five towers that were rated a three (3) that require repairs in the next two years.
 - The remaining towers should be on a five-year inspection schedule

During 2017 wind storm two structures collapsed in Tesla-Salado-Manteca 115kV line and a double dead-end structure has fallen in West Sacramento-Brighton and Rio Oso-West Sacramento 115kV line.

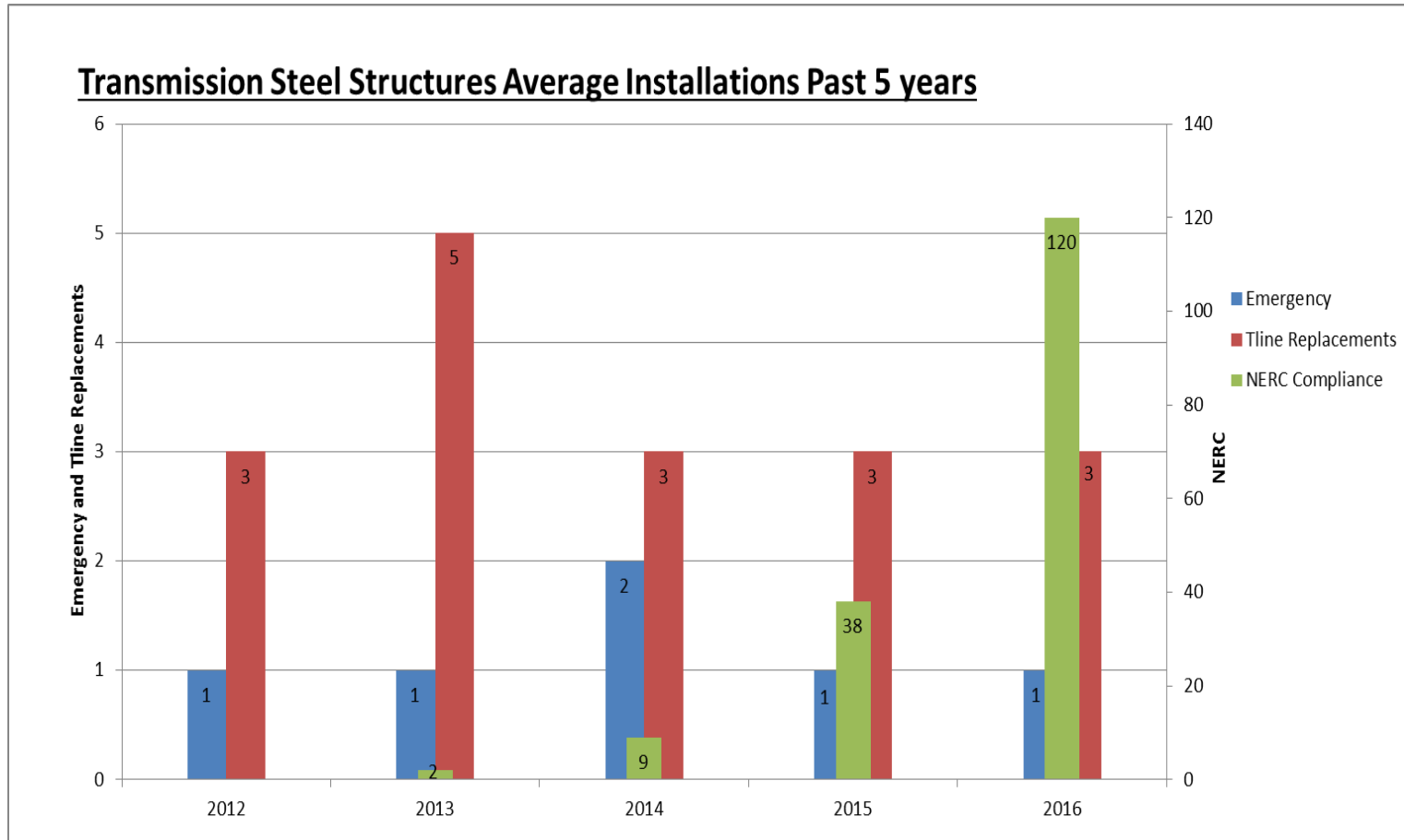


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Capital Investment Plan



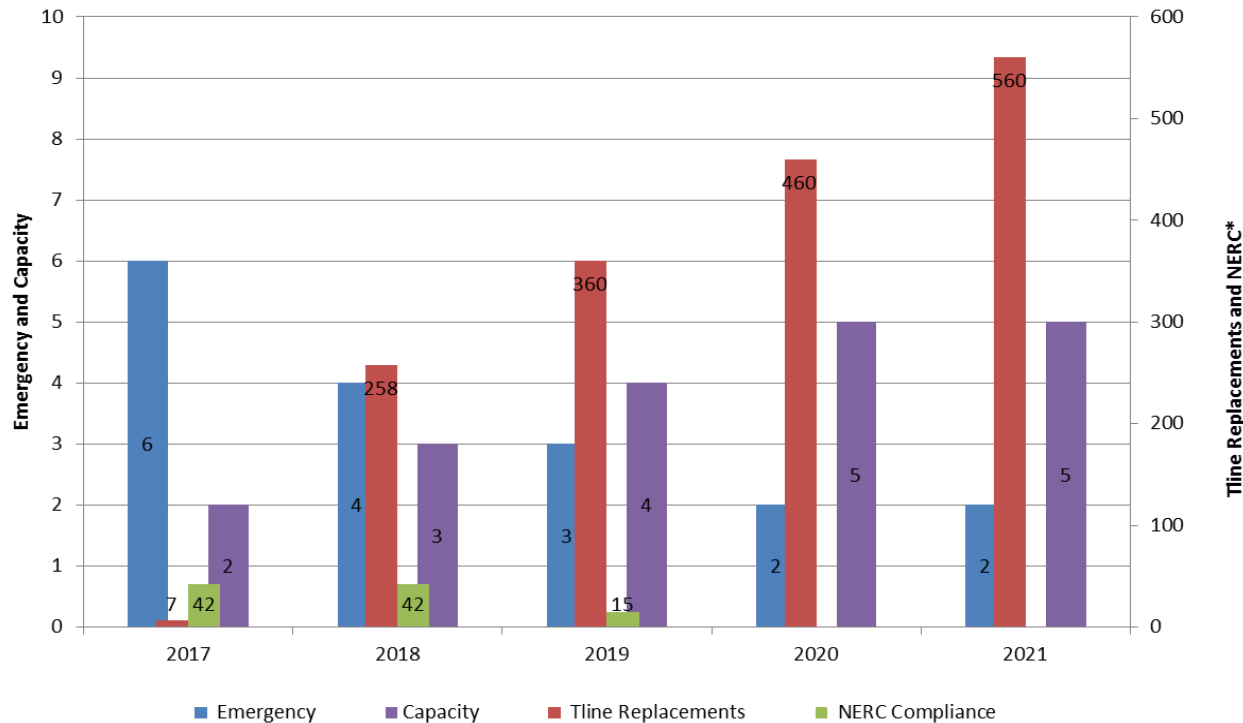
Capital Investment Plan – Steel Structure Replacement





Capital Investment Plan – Steel Structures Replacement Plan

Transmission Steel Structures Average Installations Next 5 years



- Transmission line Replacement Ramp up is due primarily to recent asset condition assessments, asset failures from the recent 2017 storms, and asset deterioration from field input.



Capital Investment Plan– Steel Structures Replacement Plan: MAT Code 70S

2017

Anchor Steel Masts

- Re-anchoring 29 Lattice Steel Poles

2018

Lattice Steel Poles – Masts

- Replace 15 Structures

West Sacramento-Brighton

- Refurbish 15 foundations
- Replace 47 structures in a flood zone

Bay Water Towers

- Replace 33 structures

Bakersfield Eroded Foundations (7 structures/28 foundations)

- Midway-Kern#1 230kV (0/6-13/81)
- Midway-Renfro-Tupman 115kV (0/1-13/75)
- Midway-Kern#3 and #4 230kV (0/5-13/64)
- Midway-Wheeler Ridge#1 and #2 (0/5-6/33)
- Midway-Whirlwind 500kV (0/5-12/53)

2019

Bay Water Towers

- Partial Replacement of 87 Category 3 structures

500kV River Crossing

- Replace str. 31/132 on Vaca-Tesla
- Replace str. 109/429 on Table Mtn-Tesla

2018-2020

Brighton-Grand Island (on hold)

- Replace 180 structures

Structure Paint Initiative

- Potential Replacement of 379 structures

Obsolescence/Condition based

- The Great Western Power Milliken type towers
- Sierra type towers
- B type towers
- K type towers
- X type towers



Contents

Asset Prioritization Criteria



Asset Prioritization Criteria – Replacement Drivers

The Asset Renew prioritization criteria for High Risk assets would be based on the following fundamentals drivers:

1. Public and employee safety risk
2. Asset Health - Asset identification, Engineering Specifications, Condition, Life Expectancy
3. Reliability
4. Environmental Factors
5. Benchmark Information
6. Root Cause Evaluations of past events
7. Obsolescence
8. Bow Wave Effect
9. Financial Benefit/Cost Ratio
10. Criticality

Priority for Renewal would also take into account bundling opportunities with other programs for optimum return of investment.

The success of the criteria is dependent upon an increase of quality data from engineering, maintenance, inspections, and asset failure information.

Bay Water Replace vs Repair Strategy:

- **Priority Weighting:** Bay Water Steel Structures on the replacement list are ranked based on the following weighted factors:
 - Asset Condition Assessments Rating (Above Waterline or mudline Visual Inspections and Testing) – 45%
 - Environmental (Evaporator pond, Tidal/Bay Water, Marsh and Dry Land) – 15%
 - Wind – 15%
- **Replacement Priority Threshold:** Replacement threshold of greater or equal to priority score of 11 was determined based on locations with Asset Condition Assessment and Environmental impact similar to the 1995 tower failures.
- **Bay Water Steel Structure Plan:** Replace 32 structures due to aging structures showing signs of deteriorated steel members and concrete footing.



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Appendix

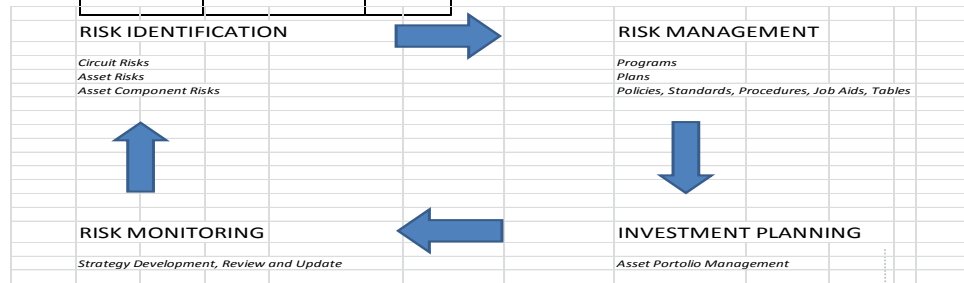
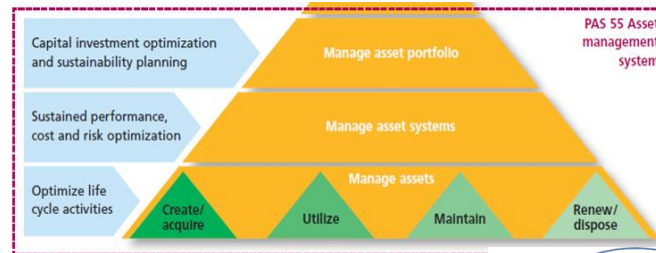


Asset One Page Summary: T-Line Strategy from a PAS 55 Framework

Material Prepared June 1, 2017



| Asset | YE 2016 Asset Count | Units |
|-----------------|---------------------|------------|
| OH Conductor | 18,437 | Miles |
| Steel Structure | 46,000 | Structures |
| UG Conductor | 173 | Miles |
| Wood Pole | 101,850 | Poles |
| Insulators | 672,125 | Insulators |



| Life Cycle | Low Risk | Medium Risk | High Risk |
|------------|--|-------------------------------------|--------------------------------------|
| Strategy | Run to Failure | Run to Failure and Cause Evaluation | Condition Base and Cause Evaluation |
| Create | Low Eng Controls | Avg Eng Controls | High Eng Controls |
| Utilize | Minimal Patrol to Continuously assess risk | Avg Patrol with less Frequency | Extensive Patrol with more Frequency |
| Maintain | No Maintenance | No Maintenance | Min Req Maintenance |
| Renew | Only Replacement No Repairs | Replace/Repair Cost Benefit = 1 | Replace/Repair Cost Benefit > 1 |
| Dispose | Leave and Do not Maintain | Leave and Maintain | Remove |

Contacts within PG&E

- Asset Strategy Boris Andino(Mgr.)

EXHIBIT F



STRUCTURES



**Prepared for: Pacific Gas & Electric
Version 4.0**

**Prepared by: Quanta Technology
May 2010**



1 Executive Summary

Transmission line structures are critical system assets that are highly reliable when constructed, loaded, and maintained within the original design parameters of the structure and the materials employed. Structures are subject deterioration of the following types:

- Mechanical – deterioration of the structure caused by some type of mechanical action
- Chemical – degradation resulting from a chemical reaction between the environment and the structure or the structure coating causing alteration to these materials
- Thermal – deterioration of the structure caused by exposure to extreme cold or heat
- Electrical – deterioration of the structure or its coating as the result of an electrical phenomenon

Of these deterioration types, mechanical and chemical are the two primary concerns for steel structures. Mechanical deterioration can result from climatic loading (wind, ice), metal fatigue due to wind-induced vibration, surface erosion from blowing particles, and external forces such as vehicular or ballistic impacts. The primary form of chemical deterioration is corrosion which can be caused by such things as soil acidity or alkalinity, environmental pollution, moisture, poor paint or coating, and cathodic reaction of dissimilar metals.

Catastrophic failure of a transmission structure is a rare event but the possibility of such a failure is something that must be taken seriously and diligently guarded against. In most cases, a complete failure of a structure is due to external conditions and forces such as weather (wind, ice, etc.) or sudden impact (e.g. vehicular) as opposed to degradation of the structure to a point of complete failure.

Asset management strategies for transmission structures are most commonly based on repair and refurbishment practices. As entire structure failures are rare, replacement of structural components, painting, and repair of damaged or deteriorated members are common actions to restore structural integrity. Corrosion is the most common reason for structure repair or refurbishment. Other frequent reasons for repair are paint deterioration, metal deformation, and loose or missing bolts.

Inspection of structures is part of routine line inspection procedures for most utilities. Aerial, walking and climbing inspections are performed on the structure as part of an overall transmission line inspection and assessment. The intervals vary by type of inspection with aerial patrol being the most frequent. A few utilities are now performing diagnostic tests on steel structures to assess below grade corrosion of the structure and/or grillages. These tests are usually driven by a



specific event or condition found during routine inspections. Technologies to perform such tests are evolving.

Steel structures are durable assets that have long service-life capability if properly maintained. Lattice towers installed in the early 1900s remain in service today at utility companies in the United States. Some utility companies have identified 10-15% rust coverage on a structure surface as the time to recoat or paint the structure. Paint coatings are expected to have a 15 year service life. The time interval varies significantly by the environmental conditions around the structure.

Because the predominant practice in the industry for management of structures is to repair or refurbish structures and components, a strategy that can effectively determine component condition and the risk the condition represents to the overall structure integrity should be implemented. The question of repair, refurbish, or replacement of a structure is largely an economic decision dependent upon the degree of deterioration or damage present. However, the long expected service life of structures, the durability of the materials, and the ability to replace parts of a structure or reinforce a foundation, drive a predominant philosophy of repair or refurbish. The industry's current ability to perform structure repairs (and even replacement) while the circuit remains energized also lends itself toward repair of components as opposed to full replacement.



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2 Introduction

The bulk of the power delivered at high voltages from the generating stations to the load centers is performed by overhead lines. Even though some urban areas demand use of underground cables for aesthetics and congestion, overhead transmission is almost always the preferred choice for reasons of maintenance, operations, and general economics. Energized high voltage (HV) conductors are supported by different types of structures designed specifically for this purpose. Transmission line structures have evolved over time from simple wood poles to engineered structures. Wood poles remain in use, however, as their utility has been proven over time. This component report will examine the use of steel structures for transmission line support. The report will review the general types and uses of steel structures, maintenance concerns with steel structures, common failure modes of structure components, corrosion impact on structures, and specific PG&E data on structure maintenance. Estimates of expected life of structures and component maintenance strategies will be discussed.

3 General Industry Summary

The general industry use of transmission steel towers is to provide support for overhead electrical conductors used to transport electric power from generation sources to customer load. Transmission towers support transmission lines carrying electricity over long distances at high voltages typically between the operating voltage ranges of 115kV–765kV. As a critical part of the transmission delivery system, structure maintenance and structure life must be considered when initially specifying the structure. For a typical transmission line project, tower costs contribute an estimated 15% to 35% of the total project cost depending upon line voltage, structure material (wood, steel, concrete), and line configuration [15].

Steel towers are generally manufactured from high strength steel producing an economical and easily constructed tower. These towers can be offered in several sizes and designs and also provide improved appearance, high reliability and reasonable maintenance cost. Transmission steel towers are applicable for either high voltage DC or AC transmission systems and may be designed to carry single or double electrical circuits. Steel towers may be installed in various terrains, environmental, and climate conditions. Additionally, steel towers can be designed as self-supporting structures for applications where wood poles are required to be guyed.

Steel towers can also provide advantages in strength, grounding, handling, and labor required for construction. Steel poles have 50% less weight for the same strength as compared to wood poles [1]. Framing for steel towers is simplified for line workers and costs are reduced by eliminating



grounds and pole bands. These advantages make steel towers a preferred choice by line workers and they are also aesthetically pleasing to the public and landowners.

3.1 Design Considerations

There are three major factors to be considered for the application of steel towers on high voltage transmission systems. The factors are expected strength, expected life, and expected performance. Steel tower manufacturers typically provide a nominal strength or minimum guaranteed strength to determine the ultimate vertical load [2]. The expected life of a steel tower is approximately 80 years (more than twice the typical service life of a wood utility pole) [1]. Steel towers may be coated with zinc or made from weathering steel to protect the steel from aggressive corrosion conditions. The expected performance of the tower will primarily depend on the ground line deflection, handling, and field use.

3.2 Types, styles and sizes

There are many different designs for transmission steel towers. The type of steel towers to be selected depends on the conditions of the land and surrounding areas, the height needed for the towers, the price of steel and other factors such as:

- Construction
- Operation
- Maintenance
- Electrical capacity and voltage of transmission line
- Physical electrical clearances

Common types of steel towers used in the industry are lattice steel towers and tubular steel poles.

- **Lattice Steel Towers** consist of a steel framework comprised of many structural components that are bolted or welded together. Many of the existing transmission lines that were built in the United States during the 1950s and 1960s used self supporting steel lattice towers. These towers are very strong, relatively light, and could be erected without the need for heavy equipment and major access roads. The base foundations require a large surface area on which to stand, which often interferes with other land uses such as agriculture. Lattice-style transmission towers, although commonly found in service today, are generally not used in new construction, dependent upon line voltage and line location.
- **Tubular Steel Poles** are hollow steel poles fabricated either as one piece or as several pieces fitted together. The compact design and slim size of tubular steel poles are particularly suitable for transmission lines installed in urban or densely populated envi-



ronments. Other advantages of tubular steel poles are as follows: Aesthetically pleasing, compactness, reduced right of way, non toxic, fully recyclable, minimal maintenance and inspection cost, and sometimes lower cost than lattice tower towers. A disadvantage of the tubular steel poles may be overall strength limitations of the structure which is proportional to the diameter of the tower.

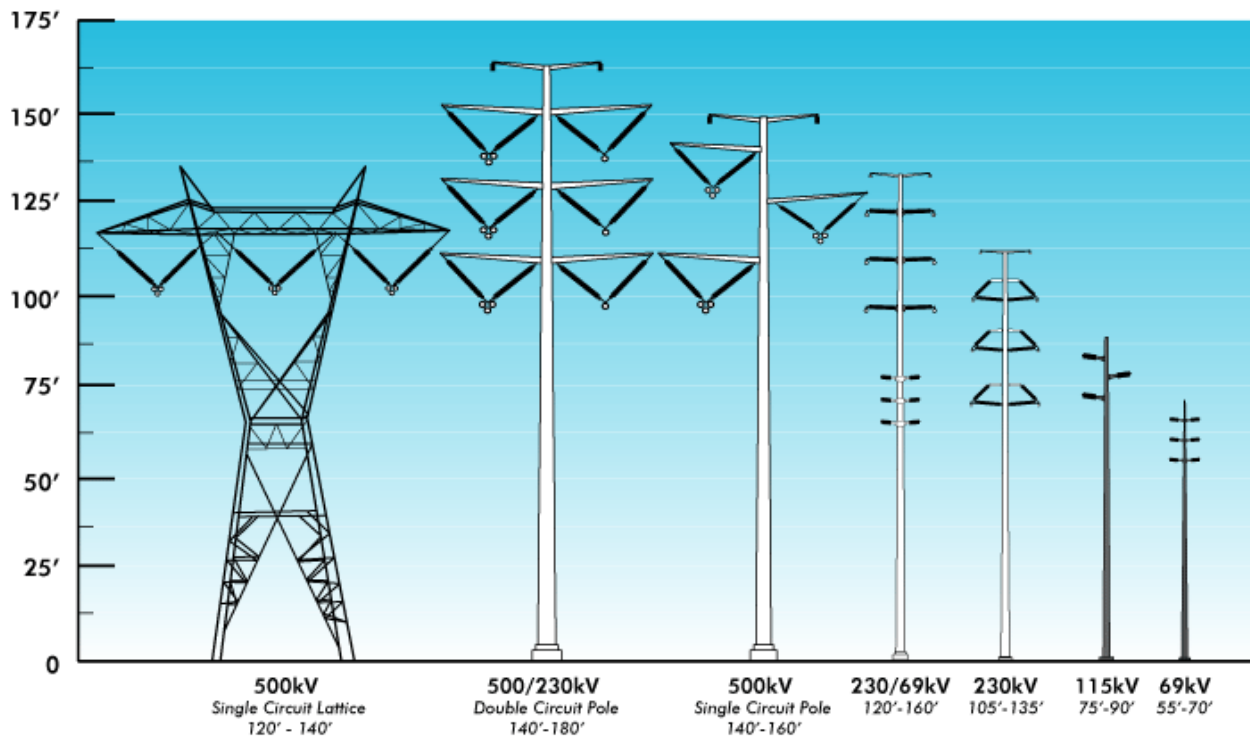


Figure 3-1. Typical industry tower types and heights by voltage class.

4 Tower Degradation Modes

4.1 Degradation types and causes

Steel towers are subject to different types of degradation that fall into the following categories [12]:

- Mechanical – deterioration of the structure caused by some type of mechanical action
- Chemical – degradation resulting from a chemical reaction between the environment and the structure or the structure coating causing alteration to these materials
- Thermal – deterioration of the structure caused by exposure to extreme cold or heat



- Electrical – deterioration of the structure or its coating as the result of an electrical phenomenon
- Biological – this mode of degradation is not considered to have any significant effect on steel transmission towers

Each of the above degradation modes can cause deterioration of a structure to a degree that they must be considered at each tower inspection or maintenance activity. However, by far the most common degradation modes are mechanical and chemical resulting in weakened structures or structure members due to mechanical impacts (e.g. vehicular or ballistic) or mechanical stresses (e.g. overloads, missing bolts, tension, cracks, elongation) or chemical activity which affects the structure coating.

- Mechanical degradation causes:
 - Impacts from moving objects such as vehicles or farm machinery.
 - High velocity impacts, such as gunshots.
 - Surface erosion from blowing particles such as snow or sand.
 - Abrasion from rubbing
 - Climate overload of structure due to high winds or heavy ice.
 - Improper manufacturing practices
 - Fatigue caused by vibration of members or connected components
 - Surface corrosion
 - Cracks
- Evidence of mechanical degradation:
 - Bent or deformed members
 - Surface corrosion
 - Cracks
 - Holes in members
 - Elongation of bolt holes
 - Gaps at joints or connection points
 - Discoloration
 - Erosion, chipping or peeling of coating
 - Missing bolts
- Chemical degradation causes:
 - High acidity or alkalinity
 - Cathodic reaction due to dissimilar metal proximity
 - Poor coating quality (material or application)
 - Moisture
 - Ultraviolet light
 - Chemical concentrations
- Evidence of chemical degradation
 - Coating deterioration (blistering, peeling, flaking, etc.)



- White oxide on galvanized surfaces
- Rust staining
- Pitting

Catastrophic failure of a transmission structure is a rare event but the possibility of such a failure is something that must be taken seriously and diligently guarded against. In most cases, a complete failure of a structure is due to external conditions and forces such as weather (wind, ice, etc.) or sudden impact (e.g. vehicular) as opposed to degradation of the structure to a point of complete failure.

More common “failures” of steel structures are failures of structure components that do not cause a complete failure of the overall structure. Structural members, bolts, foundations, or other parts of the overall structural system all are subject to different types and times of degradation. The most prevalent enemy of steel structures is corrosion and this review is therefore focused on corrosion issues.

Other most likely risks to steel towers are from metal fatigue, generally due to vibration, and cathodic reaction due to proximity of dissimilar metals. While both of these degradation modes must be considered during inspections and recognized as risks to structural integrity, they are not often cited by utility companies as widespread problems. Metal fatigue that occurs due to vibration is typically in the form of elongation of bolt holes, loosening and loss of bolts. This is an issue that progresses with age of the structure. This type of deterioration should be a focus of any visual inspection procedures, especially climbing inspections where the best proximity and visibility of potential problems can be experienced. While this type of deterioration is common in the industry, it is typically managed by inspection and repair processes and generally considered to be a manageable situation.

Deterioration of steel tower members due to cathodic reaction is an identifiable risk resulting most often from the proximity of underground pipelines to the towers. This again is a manageable issue since the location of pipelines or other metal infrastructure that could affect tower condition should be known. In those cases where the condition is known, the maintenance strategy should include regular inspection of the tower components including diagnostic tests for the presence and/or progression of corrosion.

4.2 Corrosion dynamics

Few if any reference resources exist to guide engineers regarding corrosion inspection and mitigation. Complex environmental dynamics affect corrosion including: soil resistivity, water table, soil chemistry, ground water chemistry, quality of original galvanizing, salt water, brackish wa-



ter, topography, soil type, micro biology, stray currents from cathodically protected pipelines and DC powered mass transit systems, etc.

Electrical system dynamics affect corrosion including: copper grounding systems, proximity to substation ground beds, and long line effects caused by bonding structures to the same electric potentials.

The science of corrosion engineering has evolved greatly with regards to buried pipelines, storage vessels, nuclear containment vessels, etc. The potentially fatal consequences of a failure, in pipelines and containment vessels, have driven jurisdictional authorities to mandate inspections and maintenance. As a result, the science of corrosion engineering has evolved greatly over the past 50 years. Conversely, the robust design of the electric utility steel infrastructure has so far prevented high profile failures that would bring regulatory scrutiny to bear. As a result very little knowledge has been built around understanding corrosion mechanisms on steel infrastructure. Robust design does not prevent corrosion it lengthens the time necessary for corrosion damage to become structurally significant. Many steel tower, system backbone, lines have been in service 34-40 years or more. The probability of a corrosion induced failure of a steel tower will likely become greater every year.

4.3 Corrosion mechanisms

This includes a determination of corrosion mechanisms affecting the structures and the severity of the corrosion, the need for repairs/remediation and the establishment of the best methodologies for repairs and remediation. A thorough understanding of corrosion mechanisms that relate to these structures is essential to establishing the key predictive parameters that will be examined during the field inspection phase of the project.

Corrosion of a metal is an electrochemical process governed by electrical laws. A corrosion cell is comprised of four elements:

- 1) An anode which is a metal that gives up electrons,
- 2) A cathode which is a metal that receives electrons,
- 3) An electrolyte which is an ionized solution capable of conducting electricity, and
- 4) A metallic path that can support electron flow.

In a corrosion cell, electrons migrate from the anode to the cathode leaving a surplus of positively charged ions that combine with negatively charged hydroxyl ions in the solution to produce corrosion oxides. A typical corrosion cell is shown in Figure 4-1.

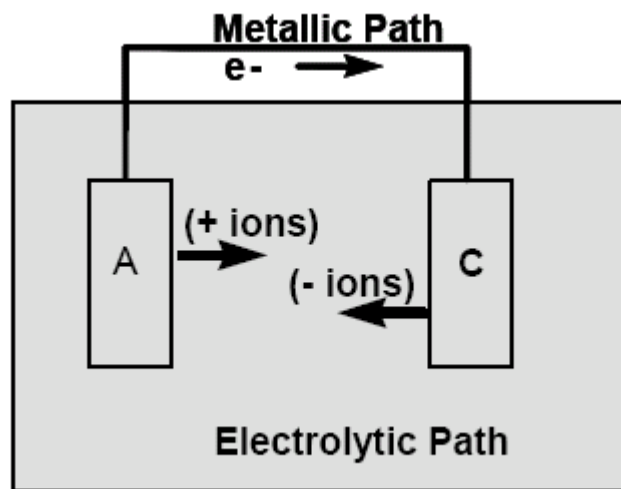


Figure 4-1. Typical Corrosion Cell

Environmental and operating factors that can influence and accelerate corrosion rates include:

- 1) Non-homogeneous environments (Dissimilar soil conditions),
- 2) Differential aeration (Differential oxygen conditions),
- 3) Bimetallic Couples (Galvanic Couple)
- 4) Environment pH¹ (pH < 6 can accelerate corrosion of carbon steel and galvanized steel),
- 5) Velocity (movement of the electrolyte around a metal can increase corrosion rates), and
- 6) Temperature² (corrosion rate increases with increasing temperature).

Establishing a reasonably conservative estimate of corrosion growth rates requires consideration for unique circumstances where corrosion of underground and submerged structures may be greatly accelerated. Such conditions include evidence of microbially influenced corrosion (MIC), corrosion caused by stray direct current and corrosion caused by induced alternating current. MIC in soils has been documented to occur at rates approaching 6mm/yr. (0.150in/yr (150mpy)). An example of the corrosion morphology associated with MIC is shown in Figure 4-2.

¹ pH is defined as the negative logarithm of the hydrogen ion content.

² The rate of electrochemical reactions doubles for every 10 degree C rise in temperature.



Figure 4-2. Corrosion Caused by MIC

The effects of stray direct current (DC) on established corrosion rates cannot be readily quantified due to the significant metal removal power of DC currents. Rates of 10mm/yr (250mpy) are expected. An example of the corrosion morphology associated with DC interference current is shown in Figure 4-3.



Figure 4-3. Corrosion Caused by Stray D-C

In recent years corrosion of carbon steel structures has been documented as a result of induced AC. Corrosion rates of 2.4 mm/yr (60 mpy) have been documented on pipelines with high quality dielectric coatings. Critical current densities of 100 amperes/m² are necessary for AC assisted



corrosion requiring pinhole defects in coatings to concentrate the current density. An example of the corrosion morphology associated with AC interference current is shown in Figure 4-4.



Figure 4-4. Corrosion Cause by Stray A-C

Absent accelerating factors, corrosion growth rates for carbon steel buried in soils and in seawater marine environments are typically less than .25 mm/yr (10 mpy). Table 1 lists typical values of corrosion rates for carbon steel in soil environments.

Table 4-1. Uhlig's Corrosion Rate Data in Soils as a Function of Resistivity and Drainage

| Environmental Factors | General Corrosion Rates, mpy | | | Pitting Corrosion Rates, mpy | | |
|-------------------------|------------------------------|---------|---------|------------------------------|---------|---------|
| | Maximum | Minimum | Average | Maximum | Minimum | Average |
| Soil Resistivity | | | | | | |
| Less Than 1,000 | 2.5 | 0.7 | 1.3 | 12.2 | 4.3 | 7.9 |
| 1,000 to 5,000 | 2.3 | 0.2 | 0.7 | 17.7 | 2.0 | 5.5 |
| 5,000 to 12,000 | 1.3 | 0.2 | 0.7 | 9.1 | 2.4 | 5.5 |
| Greater Than 12,000 | 1.4 | 0.1 | 0.6 | 10.2 | 1.2 | 4.3 |
| Drainage | | | | | | |
| Very Poor | 2.3 | 1.5 | 1.8 | 17.7 | 6.3 | 11.0 |
| Poor | 1.5 | 0.4 | 0.9 | 9.1 | 2.0 | 5.5 |
| Fair | 2.5 | 0.7 | 0.9 | 12.2 | 3.1 | 6.3 |
| Good | 0.9 | 0.1 | 0.4 | 7.1 | 1.2 | 4.3 |



4.4 Anticipated Corrosion Mechanisms

It is anticipated that the transmission structures under consideration will be exposed to a variety of corrosive conditions. General corrosion will predominate in relatively uniform environments while pitting and crevice corrosion can be expected in non-uniform environments. Considering the age of the structures under investigation, soil properties, chemistry and resistivity will contribute to dissolution of protective galvanizing allowing corrosion of structural members to propagate at varying rates, depending on the propensity for accelerating factors.

The galvanized structures used for transmission facilities employ a controlled bimetallic corrosion cell of zinc galvanizing applied over structural steel to mitigate corrosion of the steel. Once the zinc is consumed, corrosion of the underlying steel initiates. The corrosion of zinc, used in galvanizing in soils is generally a function of soil type, with pH perhaps playing a more dominant role than other factors (except for bacteria which can greatly accelerate corrosion of galvanized structures in soil). Corrosion rates of zinc in soil will greatly increase with decreases in pH.

Past experience has shown that the configuration of the structures introduces opportunities for concentrating corrosion in two distinctive regions:

- 1) Atmospheric to below ground transition, and
- 2) Water table transition.

At the atmospheric to below ground transition, corrosion cells are established due to the abundant availability of oxygen and moisture in the transition between above and below grade.



Prevailing rains can concentrate atmospheric pollutants due to ponding of rainwater in this immediate region. This ponding establishes differing chemical environments in contact with the same structural member as well as establishes corrosion cells with adjacent tower legs.

As structural members encounter deeper soils, they may be partially installed in the water table. Under this condition, corrosion cells can develop between the oxygen starved water table and the well aerated soil environment above the

water table. This can establish differential aeration corrosion cells and can promote corrosion from anaerobic bacteria. Bimetallic coupling to copper grounding can exacerbate the corrosion.



In some cases concrete footings can also establish corrosion cells between metal embedded in the concrete and the portion direct buried in soil.

It is also anticipated that varying soil environments can promote corrosion cells between tower legs and possibly long-line corrosion cells between adjacent towers under certain grounding and bonding configurations. Stray DC interference may also be encountered in collocated rights-of-way with buried pipelines or nearby DC operated transit or mining systems and industrial plants using DC processes (such as aluminum plants). Difficulty arises when the corrosion loss occurs on deep structural members that are typically inaccessible for visual inspection. In these cases operators must rely upon indirect inspection methods that have a high degree of predictive capabilities.

Since the anticipated corrosion mechanisms are electrochemical in nature, it is reasonable to expect that electrochemical measurements and diagnostic techniques that have been successfully used on a wide variety of structures to identify and quantify corrosion will be equally successful for the proposed transmission structures.

5 Industry Data - Structures

The electric utility industry worldwide approaches the maintenance and asset management of transmission towers in a relatively consistent manner. Repair and refurbishment are the primary infrastructure management philosophies with replacement occurring as necessary to avoid complete failures. The durability and maintainability of the towers coupled with the economics of replacement are the primary drivers for the repair/refurbishment practices.

The International Council on Large Electric Systems, commonly known as Cigre', conducted a worldwide survey in 2003 that gathered responses from sixty-one transmission line owners. This comprehensive study reviewed management philosophy, maintenance practice, types and causes of defects, inspection tools and methods, and general information on population ages. The results of that report [13] are reviewed in summary here, with the complete report provided as part of overall project documentation. The summary information is presented as qualitative information with no statistical significance. Additionally, Quanta Technology is conducting interviews with US utilities on the same topics to identify any widely varying practices than those reported.

5.1 Structure management criteria

5.1.1 Decision criteria

The ranking of criteria for management decisions on maintaining transmission structures is shown below. The percentage of respondents identifying each item is also given.



| | |
|---|-----|
| 1. Probability of collapse | 47% |
| 2. Symptoms of defects | 39% |
| 3. Sources of defects | 35% |
| 4. Network performance (availability) | 30% |
| 5. Existing condition (compared to original strength) | 27% |
| 6. Available budget | 21% |

The results of the survey section also confirmed an earlier Cigre' finding that economic analysis of optional courses of action on a structure is the leading quantitative criterion for deciding what action to pursue to repair, refurbish, or replace the structure.

5.1.2 Types of maintenance

The types of maintenance performed by the respondents to the survey were ranked as found below. The percentage of respondents performing each type of maintenance is also shown.

| | |
|---|-----|
| 1. Maintenance: occasional localized repair | 98% |
| 2. Maintenance: routine conservation | 86% |
| 3. Life extension (improving residual strength) | 84% |
| 4. Refurbishment (restoring original design strength) | 81% |
| 5. Upgrading (increasing original strength) | 70% |

5.1.3 Reasons for maintenance

The most common conditions that require structure maintenance were identified and ranked as found below. The percentage shown is the measure of respondents that found each issue to be the number one priority for maintenance of their equipment.*

| | |
|------------------------------|-----|
| 1. Vegetation | 47% |
| 2. Minor corrosion | 36% |
| 3. Paint deterioration | 27% |
| 4. Deformed support elements | 26% |
| 5. Loose bolts | 19% |

*Percentages were determined using a geometric weighted score calculation for each priority level (1-5). Therefore totals exceed 100%.



5.1.4 Reasons for refurbishment / life extension

The leading reasons given for performing refurbishment or life extension on structures were ranked as follows with percentages indicating the measure of respondents that identified each item as the number one priority:

| | |
|---|-----|
| 1. Extensive corrosion – normal weathering | 38% |
| 2. Extensive corrosion – industrial pollution | 27% |
| 3. Connection to foundation – local corrosion | 19% |
| 4. Deformation by vandalism | 16% |
| 5. Deformation of cross-arms | 16% |
| 6. Deformation of support shaft | 12% |
| 7. Support inclination | 12% |
| 8. Support deformation due to foundation settlement | 10% |
| 9. Global support deformation | 6% |

5.1.5 Reasons for upgrading/replacing

The following reasons for upgrade of structures were given by respondents and are shown in the same manner as the previous categories:

| | |
|--|-----|
| 1. Higher ground clearance | 35% |
| 2. Line capacity increase – conductor change | 28% |
| 3. Higher operating temperature | 24% |
| 4. Installation of OPGW or other apparatus | 17% |
| 5. Higher voltage | 17% |
| 6. Higher meteorological loads (wind, ice) | 15% |
| 7. Increase internal clearances | 9% |
| 8. EMF requirements | 6% |

5.2 Inspection Practices

5.2.1 Visual inspection modes

Participants were surveyed on type and period of maintenance inspections of overhead line supports. Responses were received from 104 companies. Each company reported on their use of the



following types of visual inspections. The percentage of the 104 respondents using each inspection type is given also.

- Walking 74%
- Vehicle 23%
- Climbing 63%
- Helicopter 66%

These percentages are for all high voltage lines. For higher voltage lines (>150 kV) the percentage of companies using helicopter inspections rose to 74% while the percentage of use of the other inspection methods remained the same.

5.2.2 Visual inspection intervals

The average inspection period for each inspection type was reported as follows:

- Walking 1.4 years
- Vehicle 1.4 years
- Climbing 4.2 years
- Helicopter 1.5 years

Climbing inspections were reported to be done on an average of every 3 years for transmission lines that are considered “strategic” lines.

In addition to the inspection interval, participants were asked if a sample of structures were inspected at that interval or the entire population. Following are the average sample sizes for each inspection type and interval:

- Walking 1.4 years 57%
- Vehicle 1.4 years 87%
- Climbing 4.2 years 53%
- Helicopter 1.5 years 94%

For “strategic” lines, the samples for walking and helicopter inspections were reported as 90% and 95%, respectively.



5.3 Defects – Type and Cause

5.3.3 Commonly reported defects

Common defects or problems reported from inspections were as shown below. The percentage indicates the percent of responses that indicated that issue as a leading concern.

| | |
|--|-------|
| 1. Structural steel corrosion | 31.2% |
| 2. Painting or coating | 30.9% |
| 3. Loose or missing bolts, nuts, washers | 19.8% |
| 4. Foundation connection | 13.8% |
| 5. Concrete deterioration | 13.5% |
| 6. Deformation of support elements | 12.8% |
| 7. Missing or deformed stays, guys | 12.5% |

5.3.4 Causes of structure collapse

The following reasons for failure of structures were reported by the participants with the percentage indicating the percent of responses that identified each issue as a leading cause of failure. (It should be noted that vehicular impact is not listed and was not an option in the questionnaire.)

| | |
|--------------------------------|-----|
| 1. Wind loading | 29% |
| 2. Wind and ice loading | 17% |
| 3. Vandalism | 13% |
| 4. Ice loading | 12% |
| 5. Cascading failure | 11% |
| 6. Material defect | 11% |
| 7. Conductor breakage | 7% |
| 8. Conductor vibration fatigue | 6% |
| 9. Delayed maintenance | 6% |

5.3.5 Corrosion

Corrosion is considered the leading issue for steel transmission structures and was cited in this survey as the most prevalent type of defect noted in inspections. For that reason, more detailed investigation into types, causes and impacts of corrosion was undertaken. Following are survey results on this topic:



Type/cause of corrosion

| | |
|--|-----|
| 1. Normal weathering | 47% |
| 2. Industrial pollution | 25% |
| 3. Salt corrosion | 18% |
| 4. Gap corrosion | 8% |
| 5. Heavy vegetation in temperate zones | 7% |
| 6. High humidity in temperate zones | 5% |
| 7. Inter-crystalline corrosion | 5% |

Reason for corrosion

| | |
|-------------------------------------|-----|
| 1. No galvanizing | 15% |
| 2. No re-painting | 14% |
| 3. Insufficient/delayed maintenance | 11% |
| 4. Weathering steel | 10% |
| 5. No painting | 9% |

Components affected by corrosion

| | |
|---------------------------------|-----|
| 1. Support footing area | 27% |
| 2. Nuts on bolts | 26% |
| 3. Secondary members of lattice | 25% |
| 4. Complete support member | 21% |
| 5. Main members of lattice | 19% |
| 6. Bolt shaft | 17% |
| 7. Washers | 17% |
| 8. Connections between bars | 16% |
| 9. Gusset plates | 12% |
| 10. Welding seams | 6% |

5.4 Summary of Inspection Practices

In the introduction of this report section it was stated that the data is from a Cigre' survey completed in 2003. While this may be considered as dated information, it should be remembered that



transmission structure inspection and maintenance practices are fairly constant activities in terms of new or innovative methods being used. The data is intended to provide a snapshot of global practices for line inspection and the types of conditions typically impacting transmission structures. As part of this project, Quanta Technology is actively pursuing similar data gathering from a few select North American companies to identify any significant deviations from the data reported here.

6 Industry Data – Foundations

A Cigre’ working group produced an industry report entitled “Refurbishment and Upgrading of Foundations” [16] in 1999 that included worldwide data on the management of primarily concrete foundations. While this report is ten years old, the basic information is still applicable to the utility environment today, based on current inquiries. With the addition of some technology to test condition of below grade components, the basic report information remains useful.

6.1 Foundation Management Criteria

The following reasons were cited by utility managers as the drivers for investigating the condition of structure foundations. The percentage of respondents (54 total) citing each reason is also shown.

| | |
|---|-----|
| 1. Condition as determined by visual inspection | 82% |
| 2. Part of a planned refurbishment program | 69% |
| 3. Age of transmission line | 52% |
| 4. Change in environmental conditions | 52% |
| 5. Planned maintenance | 51% |

The type of support predominately cited for foundation inspections were lattice towers (94%) and the most investigated types of foundations were concrete pad and chimney (66%) and steel grillages (47%). Age distribution of foundations inspected was as follows:

| | |
|----------------|-----|
| 0 to 9 years | 3% |
| 10 to 19 years | 12% |
| 20 to 29 years | 18% |
| 30 to 39 years | 25% |
| 40 to 49 years | 16% |
| 50 to 59 years | 15% |



| | |
|--------------------|----|
| 60 to 69 years | 7% |
| 70 years and older | 5% |

6.2 Types of Deterioration

Concrete foundations can experience deterioration of several types and from several sources. The common modes of deterioration are:

- Cracking, caused by
 - Reactive aggregates
 - Salt crystallization
 - Sulfate attack
 - Freeze-thaw
 - Corrosion of reinforcement
 - Ground settlement
 - Poor design or construction
- Chemical attack, caused by
 - Acids from soils and groundwater
 - Alkali aggregate reaction
 - Carbonation
 - Chloride attack
 - Efflorescence
 - Salt crystallization
 - Sulfate attack
- Physical attack, caused by
 - Unsound aggregates
 - Freeze-thaw cycles
 - Adfreeze
 - Frost/permafrost
- Corrosion
 - Reinforcement corrosion
 - Tower stub or grillage corrosion



6.3 Inspection Practices

Industry inspection practices for foundations range from fundamental visual inspections to detailed testing and diagnostic inspections with specialized equipment. The type of inspection used is progressive with each subsequent inspection practice continuing from the previous inspection and findings.

Visual Inspection

The basic inspection for foundations, as with most infrastructures, is the periodic visual assessment. This inspection typically observes any obvious displacement of the foundation, any visible deterioration of the steel and/or concrete, any changes in the tower alignment, and the presence of cracks, soil erosion, standing or ground water. A visual inspection will also include soil resistivity measurement on a periodic basis.

Second Level Inspection

Upon finding evidence of problems in a visual inspection, a second level inspection may be undertaken to investigate the specific concern(s) identified. This inspection involves some testing and is largely focused on determining the extent of a problem of deterioration. The inspection generally focuses on the element of concern of the foundation/structure systems, e.g. soil conditions, foundation condition, and/or steel condition. Tests for soil conditions include standard geotechnical procedures including borings, field tests (SPT, CPT), and dynamic penetrometer applications. Foundation testing may include verification of foundation dimensions, displacement, and deterioration. Surveying can be used to determine placement as compared to as built and surface penetrating radar can provide information on condition of concrete and foundation dimension which can identify deterioration and loss of mass. Inspection for corrosion, strength and durability can be achieved through various diagnostic approaches including half-cell potential, penetration resistance, core samples, and carbonation tests for example.

Third Level Inspection

Further inspection of a foundation would be driven by the need for more detailed information of conditions found or suspected from a second level inspection. At this point, very specific samples of concrete, soil and water would be taken for laboratory analysis. Additionally, measurement of coating thickness and tensile strength of steel components would also be completed.

6.4 Summary of Inspection Practices

Foundation inspections are part of a routine maintenance program for transmission lines. Any concerns noted during regular visual inspection must be assessed to determine if further inspec-



tion and testing of the foundation is warranted. Many inspection tests are of most value if they are part of a program that includes data collection and retention for comparative analysis over time. Tests in this category would include corrosion rate measurement, half cell potential, penetration resistance, and acoustic pulse echo among others. Second level testing and inspection can be applied at specific intervals to build intelligence on the rate of deterioration of various foundation types, components, or environments that impact condition. The appropriate interval is dependent upon the age and performance of the foundation and the observance of any visible signs of deterioration. In effect, foundation inspections are primarily visual inspection processes followed by diagnostics on an as-needed basis.

7 Equipment Service Life

7.1 Structures

Steel transmission structures have proven to have long service lives under active and thorough maintenance programs. Lattice steel structures installed in the 1920s in the US utility industry remain in service in many locations. The following Tables 7-1 through 7-3 provide a snapshot of the age of steel structure populations for six utility companies, including PG&E. These ages were derived from the Cigre' survey [13]. The information is only intended to demonstrate that structures remain in service in the utility industry well into seven or eight decades, even longer in some cases. Any need to replace transmission structures is generally more a need due to functional obsolescence than end of life condition of the structure. As lines are uprated and/or reconducted, the existing structures are sometimes not adequate for the additional loading or clearance requirements.

**Table 7-1. 115 kV Age Distribution**

| 115 kV | | | | | | |
|------------------|-------|-------|-------|-------|-------|-------|
| Decade Installed | PG&E | A | B | C | D | E |
| 1900-1910 | 14.8% | | | | | |
| 1911-1920 | 12.9% | | | | | |
| 1921-1930 | 16.7% | 17.0% | 5.0% | | | 11.0% |
| 1931-1940 | 6.7% | 7.0% | 3.0% | | | 4.0% |
| 1941-1950 | 11.8% | 4.0% | 1.0% | | | 14.0% |
| 1951-1960 | 17.7% | 26.0% | 27.0% | 36.0% | 5.0% | 8.0% |
| 1961-1970 | 9.5% | 18.0% | 25.0% | 24.0% | 18.0% | 12.0% |
| 1971-1980 | 6.4% | 17.0% | 17.0% | 18.0% | 19.0% | 29.0% |
| 1981-1990 | 2.0% | 7.0% | 16.0% | 14.0% | 17.0% | 19.0% |
| 1991-2000 | 1.0% | 4.0% | 6.0% | 8.0% | 33.0% | 3.0% |
| 2001-2009 | 0.5% | | | | 8.0% | |

Table 7-2. 230 kV Age Distribution

| 230 kV | | | | | | |
|------------------|-------|-------|-------|---|-------|-------|
| Decade Installed | PG&E | A | B | C | D | E |
| 1900-1910 | | | | | | |
| 1911-1920 | | | | | | |
| 1921-1930 | 24.3% | 24.0% | 4.0% | | | |
| 1931-1940 | 7.2% | 25.0% | 22.0% | | | |
| 1941-1950 | 28.9% | 3.0% | 2.0% | | | 30.0% |
| 1951-1960 | 21.6% | 15.0% | 14.0% | | | 17.0% |
| 1961-1970 | 11.9% | 16.0% | 46.0% | | | 20.0% |
| 1971-1980 | 3.6% | 11.0% | 10.0% | | 23.0% | 0.0% |
| 1981-1990 | 2.5% | 5.0% | 2.0% | | 70.0% | 19.0% |
| 1991-2000 | 0.1% | 1.0% | 0.2% | | 7.0% | 14.0% |
| 2001-2009 | 0.0% | | | | | |

**Table 7-3. Over 300 kV Age Distribution**

| >300 kV | | | | | | |
|------------------|------------------|-------|-------|-------|-------|-------|
| Decade Installed | PG&E (500 kV) | A | B | C | D | E |
| 1900-1910 | | | | | | |
| 1911-1920 | | | | | | |
| 1921-1930 | | 21.0% | | | | |
| 1931-1940 | | | | | | |
| 1941-1950 | | | | | | |
| 1951-1960 | | 26.0% | 0.5% | | | 25.0% |
| 1961-1970 | 76.7% | 27.0% | 19.0% | 15.0% | | 20.0% |
| 1971-1980 | 22.2% | 19.0% | 33.0% | 38.0% | | 35.0% |
| 1981-1990 | | 6.0% | 46.0% | 32.0% | 10.0% | 14.0% |
| 1991-2000 | 1.0% | 1.0% | 2.0% | 15.0% | 81.0% | 6.0% |
| 2001-2009 | 0.2% | | | | 9.0% | |

7.2 Coatings

As corrosion is the most prevalent cause of deterioration of steel structures, the life expectancy of the original coating of the steel is critical to the long term health of the structure. The American Galvanizers Association regularly produces life expectancy data on hot-dip galvanized coatings, the predominant coating for steel structures. Figure 6-1 displays life expectancy information for a hot-dip galvanized coating in a variety of environments. The service life for this chart is defined as the time until 5% rusting of the steel structure is experienced.

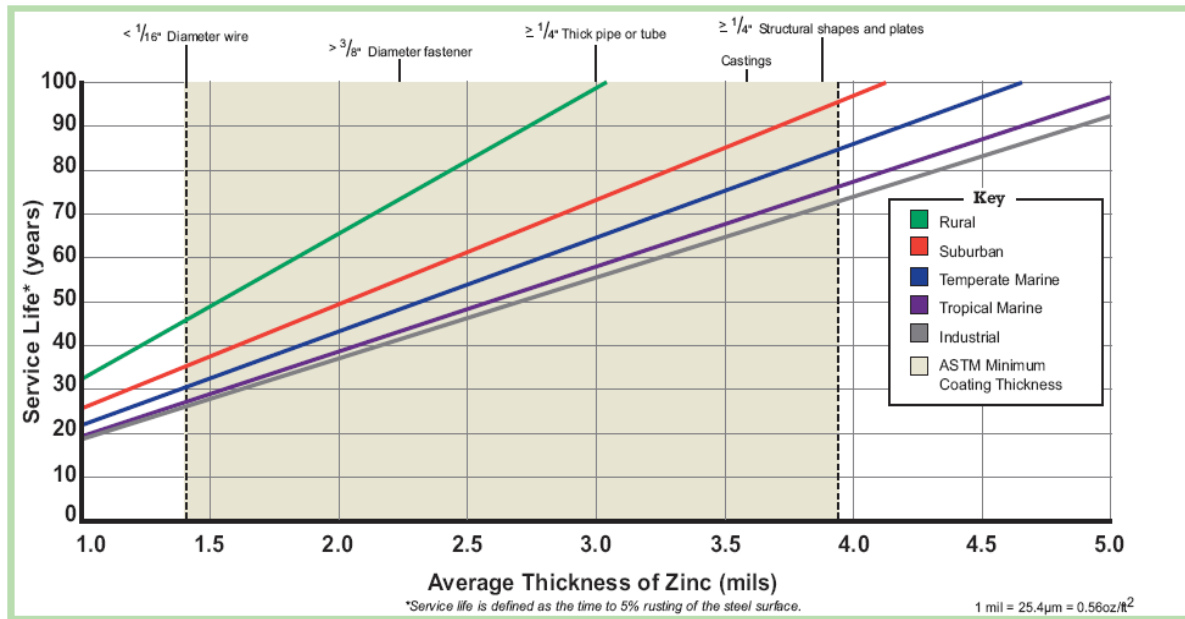


Figure 7-1. Service Life of Hot-Dip Galvanized Coatings

Source: American Galvanizers Association

One utility in Texas cited field experience as follows [14]:

- Rural structures after 50+ years had not reached 10% rust when inspected;
- Structures in a chemical environment shows corrosion at 10 years and reach 10% rust in approximately 15 years;
- Structures in a marine environment have been observed to perform the same as the chemical environment; however the rust progression is faster once the galvanic coating is penetrated.

Based on years of inspection and data collection this utility has determined that the optimum time to paint or recoat a structure is when the rust is 10% or less of the structure. The paint and process used is expected to provide a 15 year life.

A second utility that routinely inspects structures below grade has provided anecdotal information. They have found that after twenty years in the field, lattice steel towers had an inspection "failure" rate of approximately 15% with failure defined as the need for structural repair. For tubular steel poles, the failure rate was approximately 25%. Notably with steel poles, it was found that any breach of the pole coating as a result of material handling or construction, resulted in significantly more localized corrosion.



7.3 Foundations

Like towers, foundations are designed with an expected service life of approximately fifty years with actual service extending even longer. With good quality materials, construction, and maintenance, concrete foundations would be expected to have a service life equal to the structure itself.

7.4 Case Example

In 2008 a comprehensive assessment of a 35 mile transmission line at a utility was conducted to establish a base condition assessment and develop some remaining service life models [17]. This utility operates on an island nation and facilities are subject to the corrosive environment of the seacoast. The line inspected was constructed in 1977 and consists of 144 guyed towers and self-supporting lattice towers. The line environment ranges from approximately 30 feet to 1200 feet above sea level and crosses bodies of water as well as flat land.

The condition assessment included climbing inspection of 68 of the 144 towers. In addition, some components were removed for inspection and laboratory testing. The process used a “condition code” from 0-100 to describe the current condition of components (100=new, 0=end of life) and an environment code to assign factors for corrosion, wind, soil condition, and temperature (freeze/thaw) risk. A generally mild, benign environment was coded as 100, with a severe environment based on any of the factors was coded 0.

After scoring component conditions and the environment in which they were placed, service life predictions were developed for tower and foundation components. Table 7-4 gives the findings for each component, the primary deterioration mode, the environmental risk and expected service life for the severity of the environment.

This is one, somewhat simple example of a condition assessment methodology for a specific utility. The value in this case is quantification of expected service life of tower and foundation components which is found to be consistent with industry anecdotal information. Common responses to the question of what is the expected service life of towers and foundations is description of a design life of fifty years with actual service extending decades beyond that with proper inspection and maintenance.



Table 7-4. Component Service Life

| Component life in yrs vs. Environment. | | | | | | |
|--|------------------------------------|-----------|-------------|----------|--------|----------|
| | Item | Condition | Environment | 100 Mild | 50 Avg | 0 Severe |
| Tower | Twr top (Bridge / superstructure) | Rust | Corrosion | 120 | 80 | 40 |
| | Tower bottom, (Below bottom arm) | Rust | Corrosion | 140 | 95 | 50 |
| | Foundation leg connection | Rust | Corrosion | 80 | 57 | 35 |
| | Foundation concrete | Cracking | Freeze Thaw | 80 | 57 | 35 |
| | Painted tower | Chalking | Corrosion | 60 | 32 | 5 |
| | Anchor rod | Rust | Foundation | 100 | 70 | 40 |
| | Guy grip | Rust | Corrosion | 100 | 65 | 30 |
| | Guy Wire | Rust | Corrosion | 100 | 65 | 30 |
| | Twr attachments : Susp/Jumper. | Wear | Wind run | 80 | 57 | 35 |

8 Trends in Inspection

With recognition of the issues associated with aging infrastructure, more attention is expected to be given to steel tower condition throughout the industry. To date, however, little evidence exists that innovative techniques beyond traditional visual inspections are being employed.

As indicated in Section 5, walking, riding, climbing and aerial inspections of structures are done in some combination by virtually all utility companies. Frequency of inspections vary by company and by region. Not included in the findings of Section 5, however, is information regarding detailed structure inspection that includes excavation of footings, voltage or resistivity measurements, and other methods of corrosion evaluation of direct buried tower footings or of direct buried steel poles.

In most cases, utilities depend upon routine visual inspections (walking, riding, etc.) to identify apparent significant condition degradation of structures. From those inspections, more detailed evaluation of condition using diagnostic methods and/or excavation of footings is initiated. Quanta Technology is aware of only a handful of utility companies that have implemented any sort of routine diagnostic evaluation of condition of towers (PG&E being one with the current 500 kV inspection program).



Where the most in depth evaluation of condition assessment is being done it includes:

- Above ground visual inspection,
- Hand digging to excavate approximately one foot deep around footings,
- Voltage measurements above and below grade, and
- Measurement of thickness of remaining galvanized coating above and below grade.

Data collected from an inspection methodology of this type is envisioned as the input to a predictive model that will assist in scheduling and planning for maintenance, refurbishment, and replacement of structure members. At this time, however, Quanta Technology is not aware of any utility company that has implemented a predictive maintenance model based on tower corrosion data gathered in the field.

There is ongoing activity and research regarding the application of EMAT conductor inspection methodology to steel towers. At this time that methodology is being applied to assessment of guy wires, anchors and grillages.

9 PG&E Specific Data

A first level data analysis has been performed on the structure population at PG&E from the data provided. This analysis is primarily a sorting and categorizing of the data to create a representation of the variables related to the structure population in service at PG&E. This sorting includes age, voltage, material, application, location, and some review of maintenance and failure records associated with each category.



9.1 Age distribution of transmission structures (by voltage class)

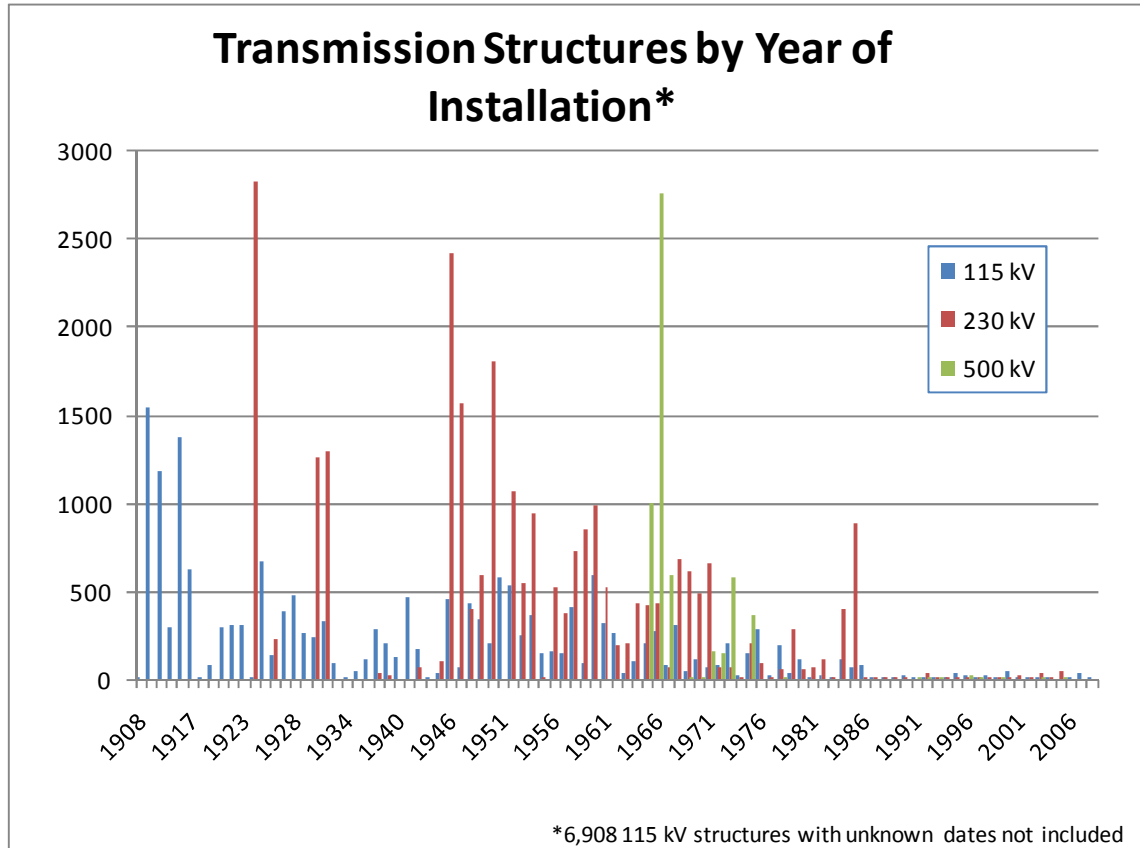


Figure 9-1. Age distribution of transmission structures

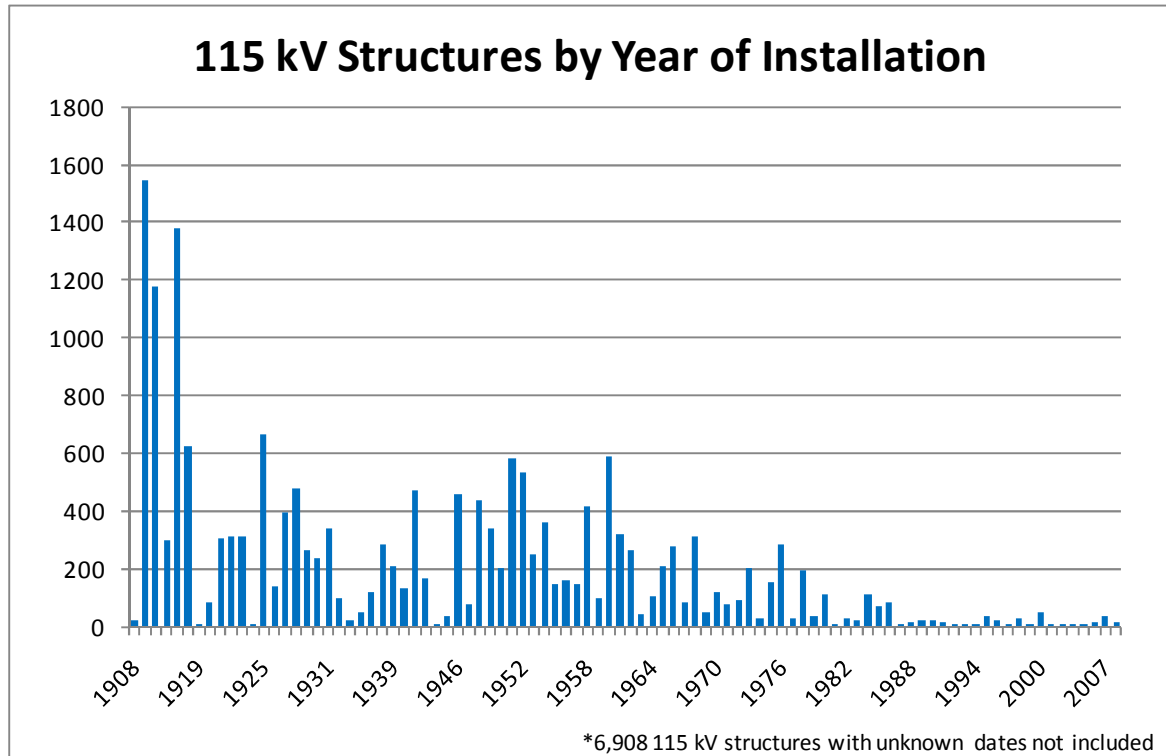


Figure 9-2. 115 kV structures by year installed

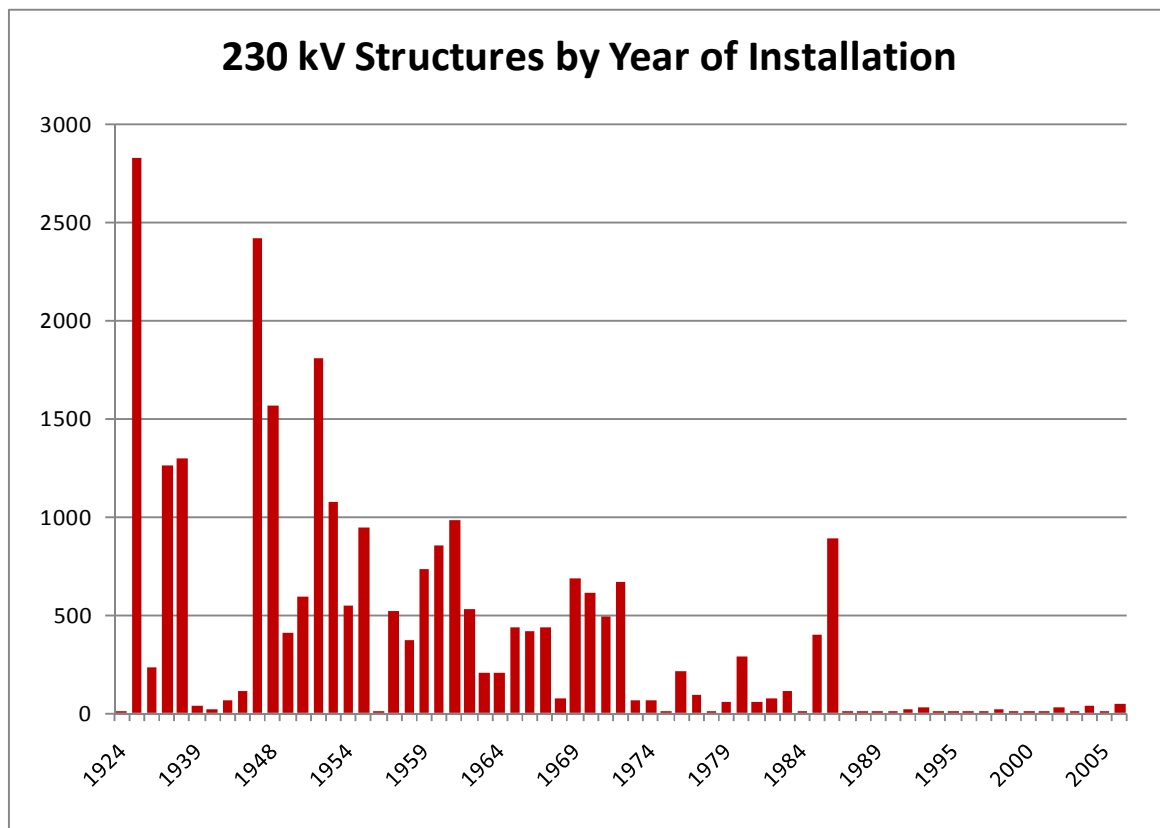


Figure 9-3. 230 kV structures by year installed

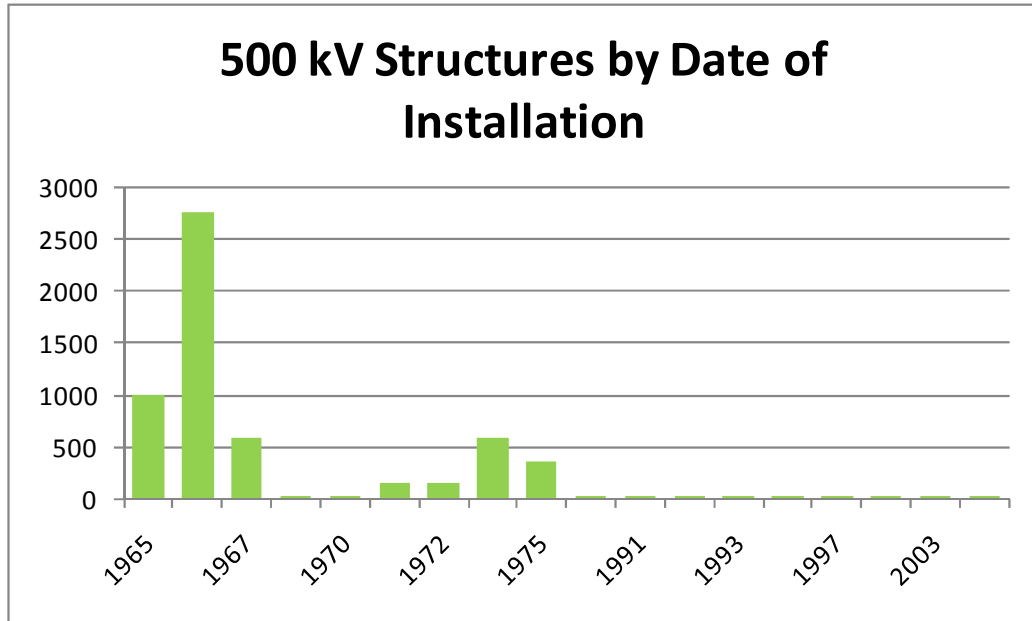


Figure 9-4. 500 kV structures by year installed

9.2 Structure work notifications

For the period January 2004 through April 2009 there are approximately 11,500 work notifications, both pending and complete, on transmission structures. A high percentage (~77%) of the work notifications report missing steps, anti-climbing guards, or platforms. The remaining 23% of the notifications report various damage conditions found on the structures that are considered for this analysis to be associated with the structural condition of the towers. This population of work notifications is approximately 2,600 in number and the distribution of the types of damage reported is shown in Figure 9-5.

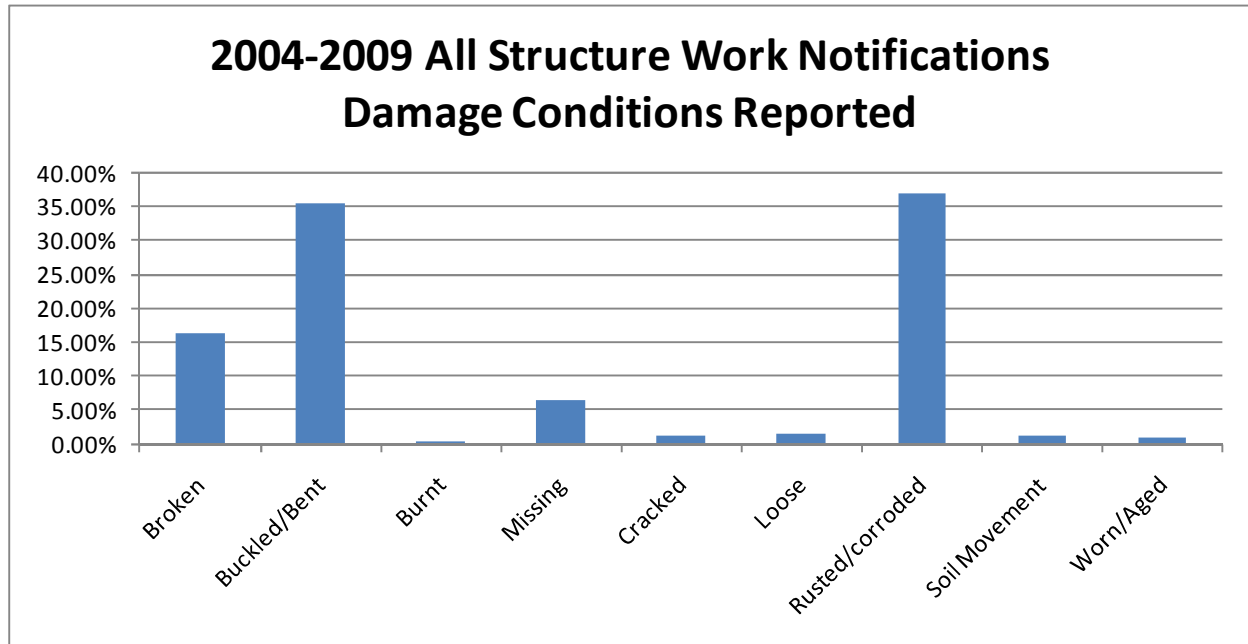


Figure 9-5. Damage codes reported

Review of the damage conditions reported by different structure components reveals a damage condition distribution as shown in Figures 8-6 through 8-8.

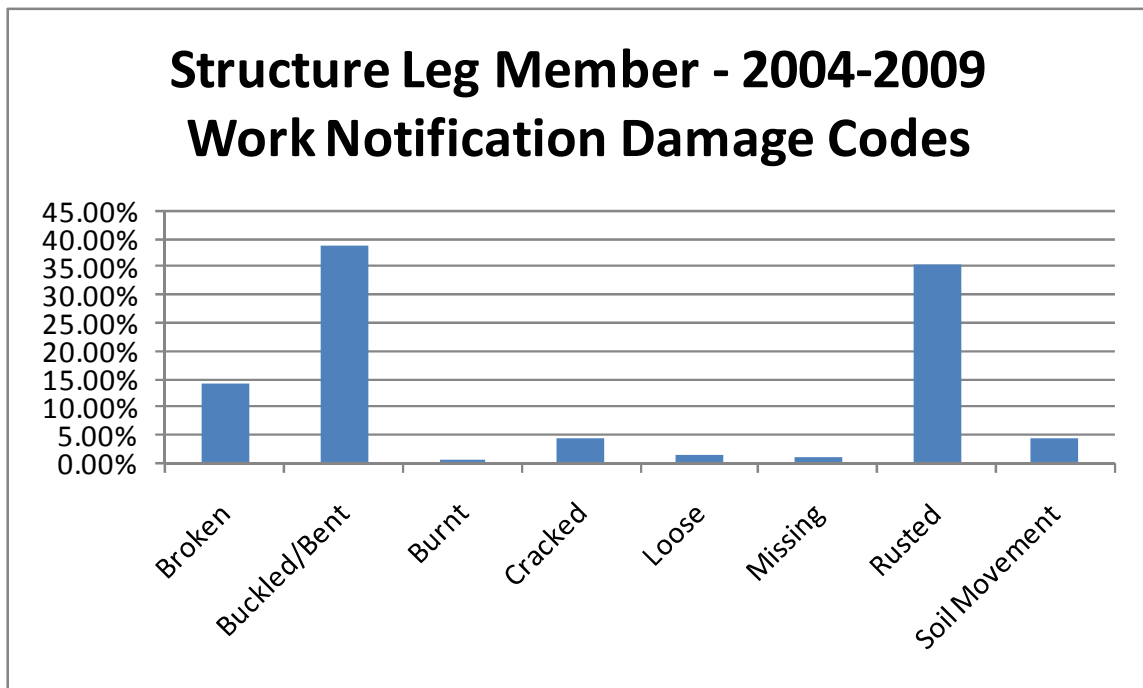


Figure 9-6. Leg member damage reports

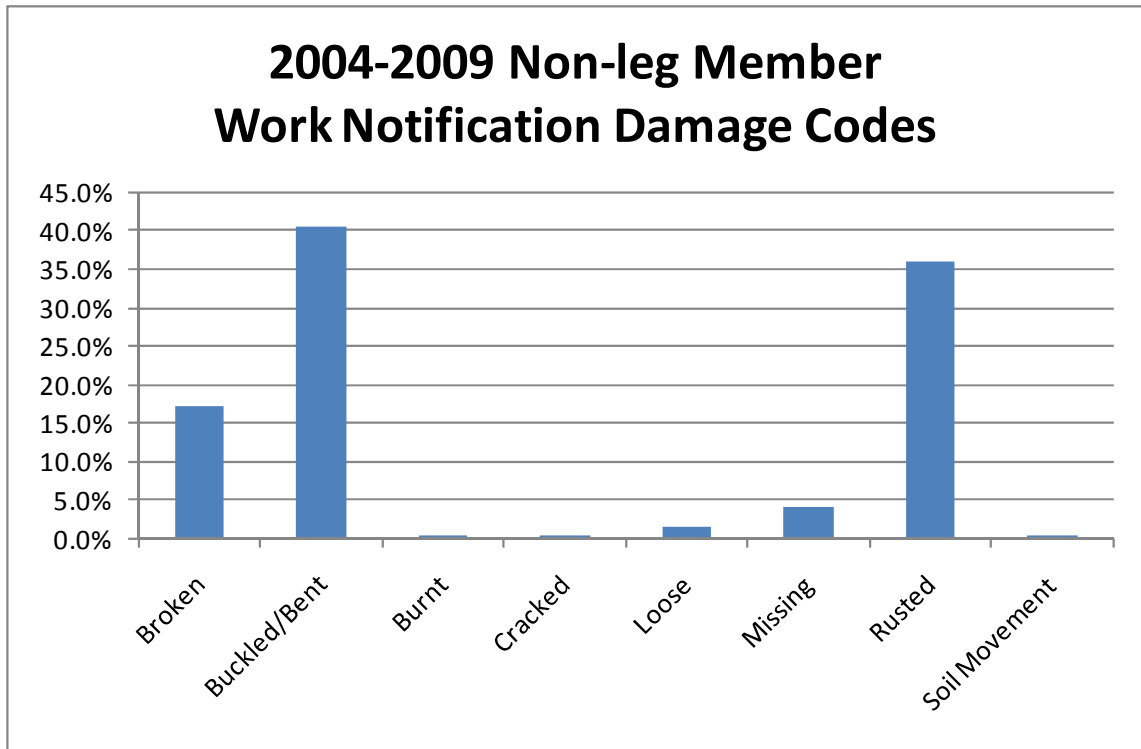


Figure 9-7. Non-leg member damage reports

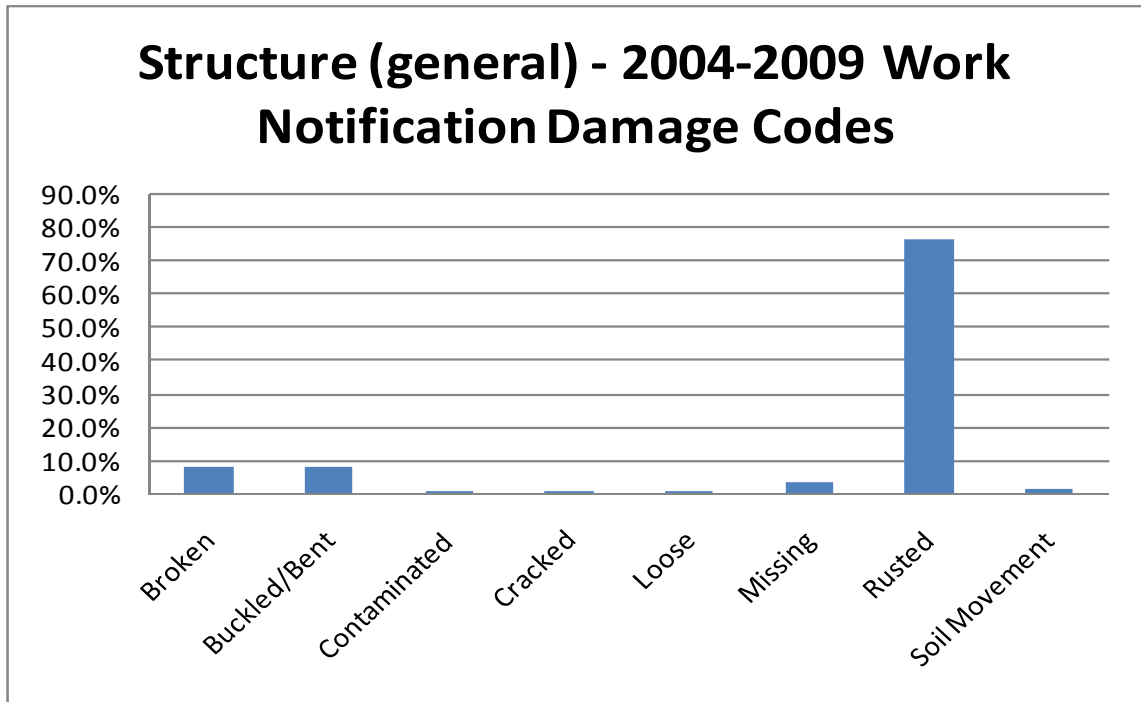


Figure 9-8. Structure (general, incl. bolts) damage reports

9.3 Age distribution of structure foundations

The following graphs display the age distribution of foundations, by type. The total numbers represented are as follows: Concrete 42,330; Earth 5,072; Pile 1,978.

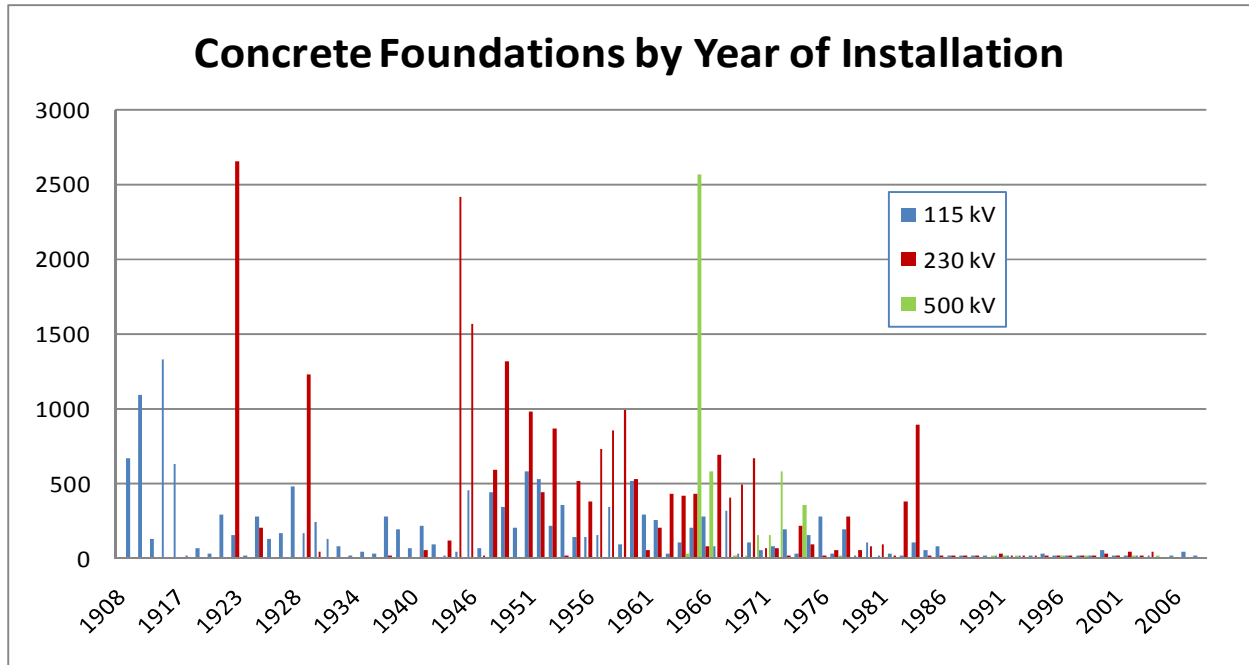


Figure 9-9. Concrete foundations

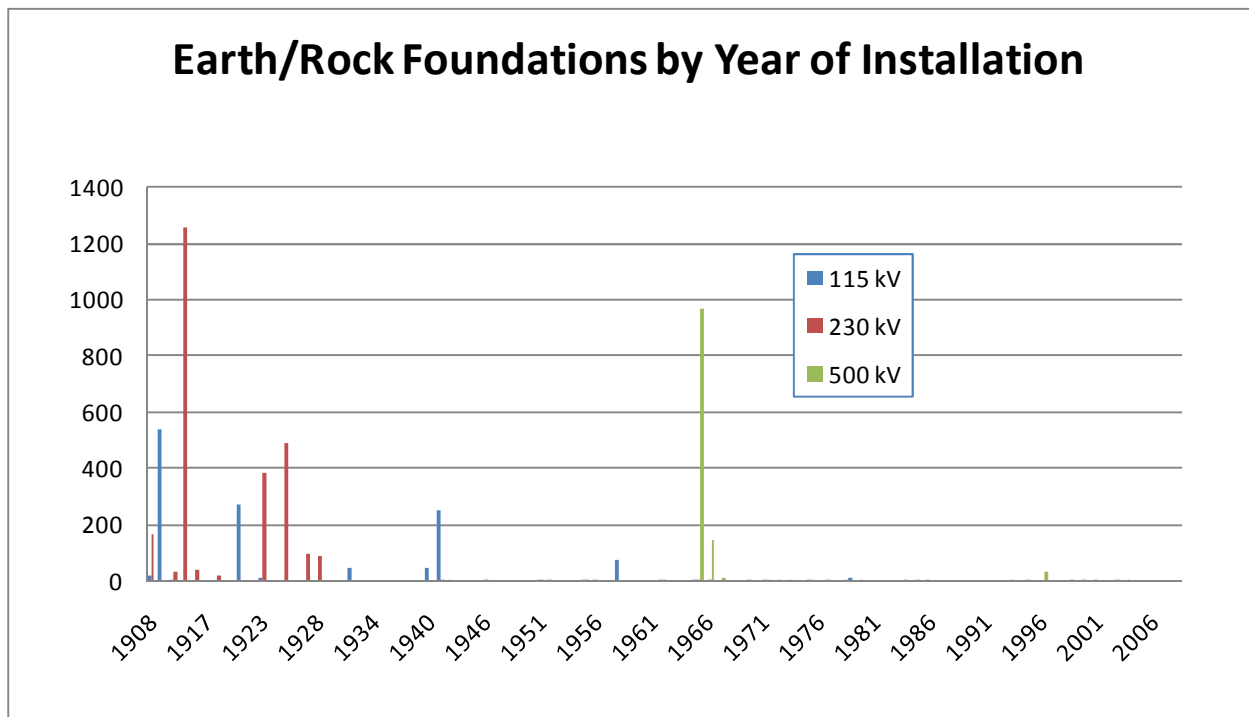


Figure 9-10. Earth and rock foundations

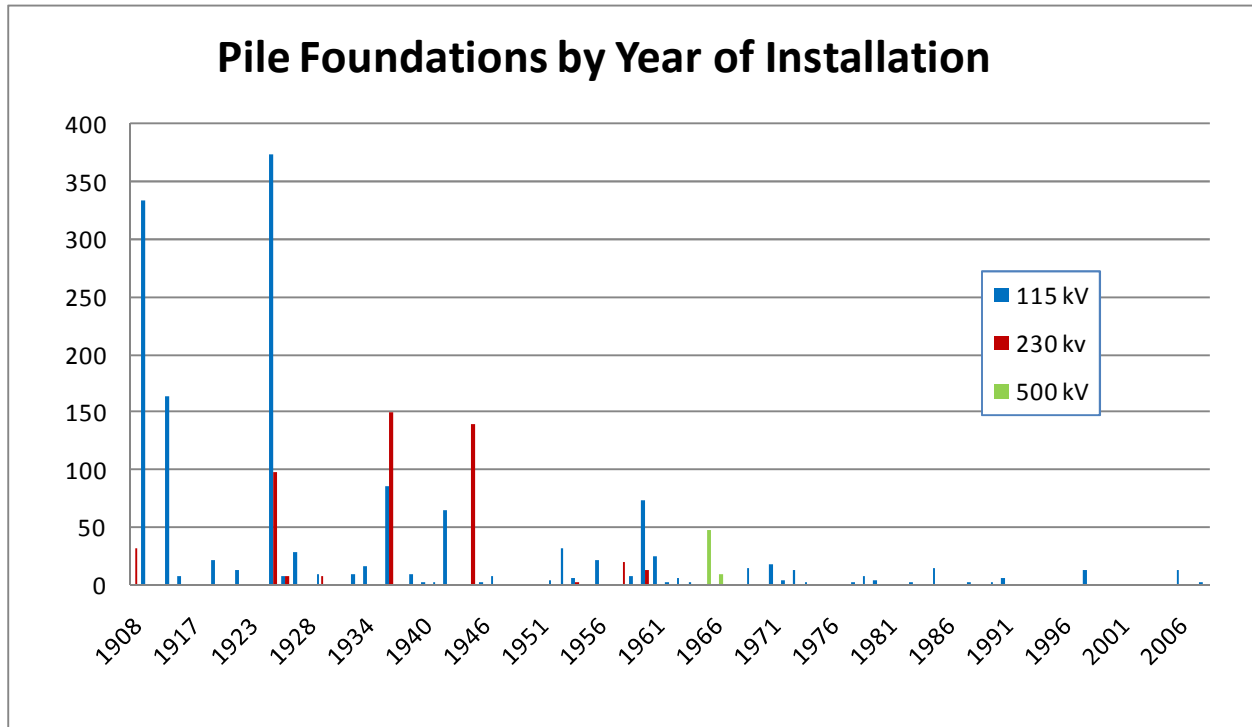


Figure 9-11. Pile foundations

9.4 Foundation work notifications

The following graphs show distribution of foundation damage codes. The total number of concrete footing records reported was 2,443 and earth footing records totaled 189.

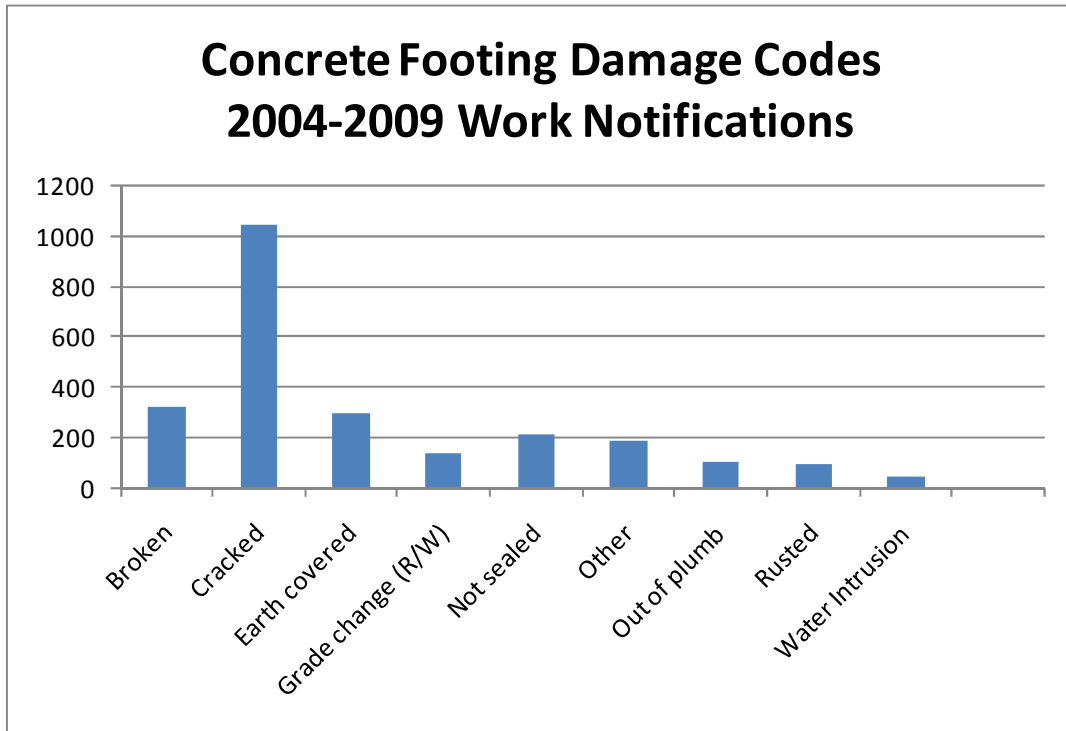


Figure 9-12. Concrete footing damage reports

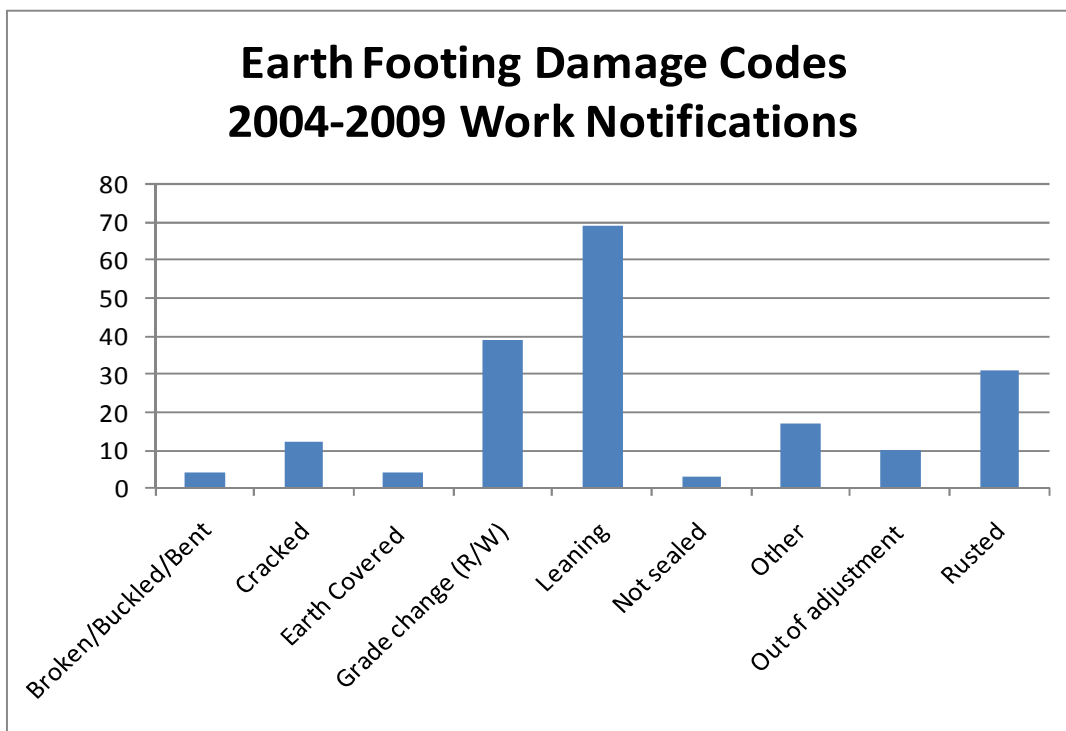


Figure 9-13. Earth footing damage reports



9.5 Anchor and guy work notifications

The following graphs show distribution work notification damage codes for anchors and hardware and guys as taken from 2004-2009 work notifications. The number of anchor/hardware records was 206 and guy records totaled 593.

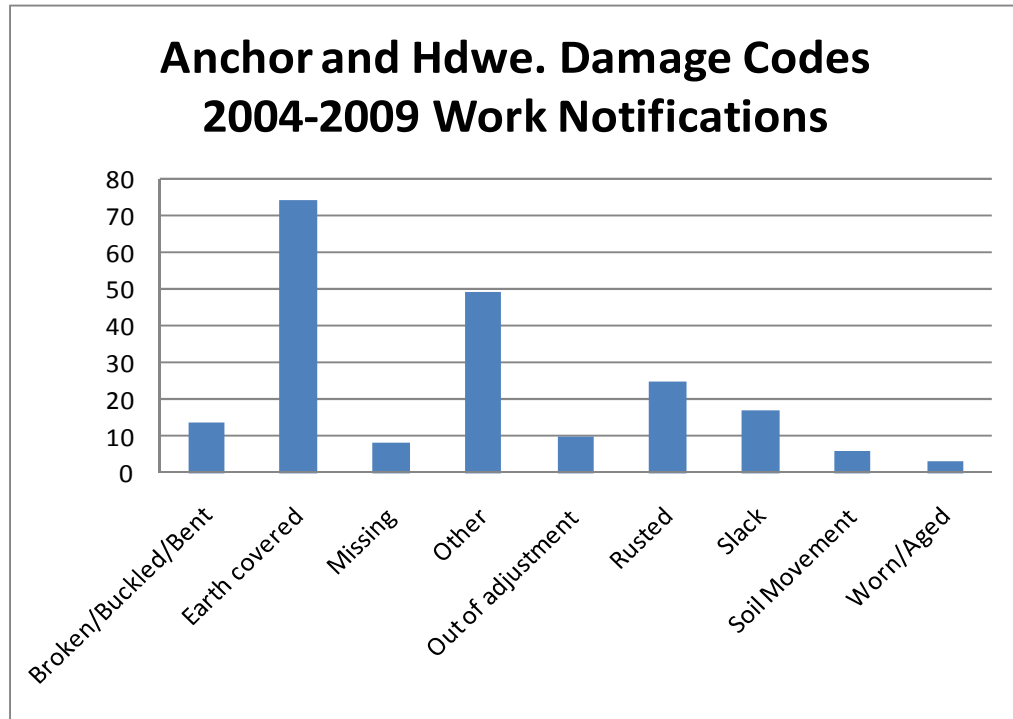


Figure 9-14. Anchor and anchor hardware damage reports

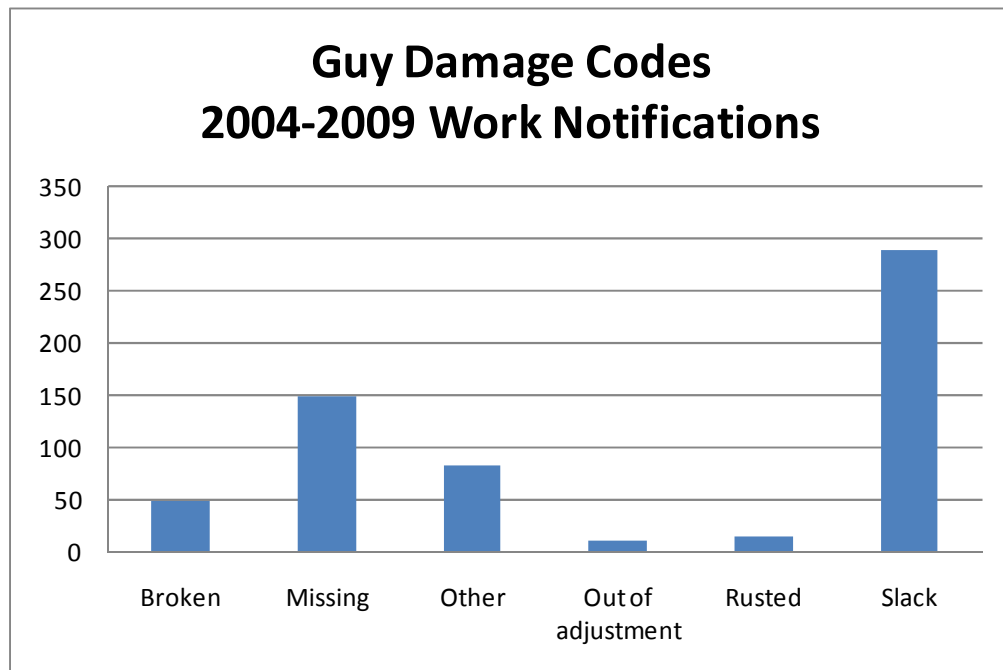


Figure 9-15. Guy damage reports



9.6 Cross arm work notifications

The following graphs show distribution of damage codes for wood and steel cross arms as taken from 2004-2009 work notifications. The total number of wood cross arm records was 1990 and steel was 34.

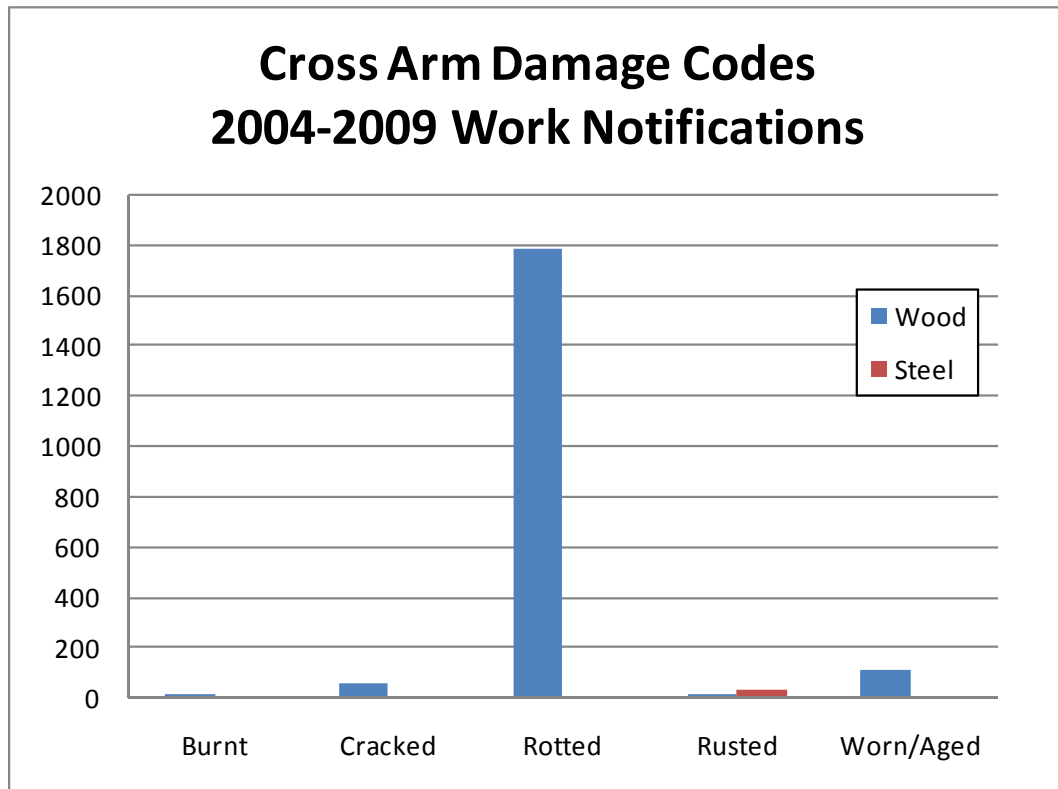


Figure 9-16. Cross arm damage reports



10 Statistical Analysis

The entire matched work notification dataset for structures is examined first to investigate the general structure failure patterns, regardless of its voltage level, damage type, and location. The analysis is then broken down to different categories by voltage levels, damage codes related to aging, and locations. It should be noted that this analysis is based only on structure component failures reported in the 2004-2008 time period, but covers a significant number of events that give insight into key failure patterns. For the purpose of this review and analysis a “failure” is defined as assumed “end of life” of a component thereby requiring significant maintenance or replacement. It does not mean complete failure of a structure.

This analysis as with others in this project, is based solely on records of end of life failure or required maintenance representing a component functional failure. The analysis therefore uses the approximate component age when identified as failed or non-functional but does not necessarily represent a complete population failure analysis. The hazard functions (failure rates) indicated in this report should be interpreted as the chance of component failure in an entire population at a given age, based on the ages of failed components as found in maintenance records from 2004-2009.

10.1 All Data

The Kaplan Meier plot is shown in Figure 10-1, this plot can be treated as a cumulative distribution function based on actual data instead of a fitted probability distribution function. Considering only the set of structures that have experienced a major failure from 2004 to 2008, the plot describes the probability that these failures have occurred before or at the time t .

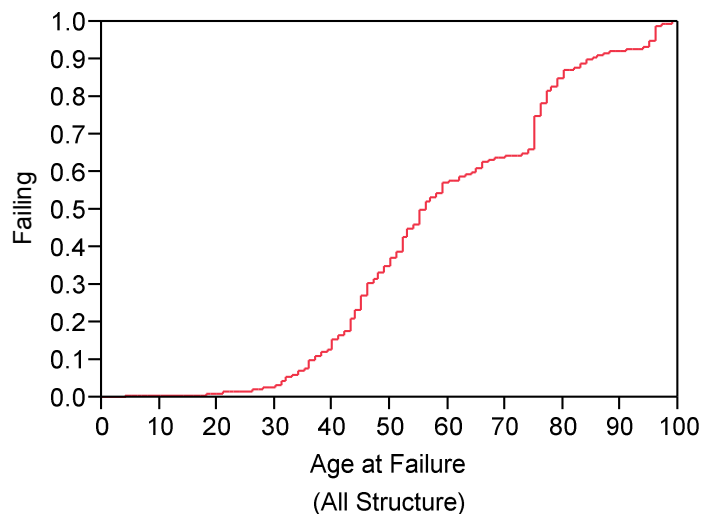


Figure 10-1. The Kaplan Meier plot of all structure failure data



The estimates of Weibull distribution parameters are: $\alpha=3.41$, $\beta=66.42$

$$f(x) = \begin{cases} \frac{\alpha}{\beta} \left(\frac{x}{\beta}\right)^{\alpha-1} e^{-\left(\frac{x}{\beta}\right)^{\alpha}}, & x \geq 0 \\ 0, & x < 0 \end{cases} = \begin{cases} \frac{3.41}{66.42} \left(\frac{x}{66.42}\right)^{2.41} e^{-\left(\frac{x}{66.42}\right)^{3.41}}, & x \geq 0 \\ 0, & x < 0 \end{cases}$$

Based on the parameters estimated above, the fitted Weibull probability density function and its corresponding survival curve (reliability curve) are shown in Figure 10-2a and 10-2b, respectively.

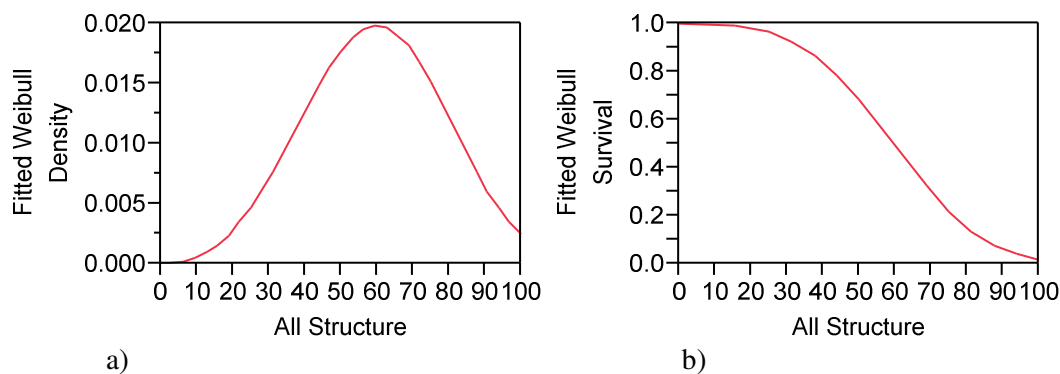


Figure 10-2. Fitted Weibull probability density function and survival curve for the set of failed structures

Figure 10-2a shows that the most frequent age of the structure failures is around 60. As shown in Figure 10-2b, the value of the survival function at age 0 is usually assumed to be 1, indicating that all structures are working properly, although there is the possibility of immediate failure. The survival function approaches zero as age increases to around 100. This is because we are only analyzing failed structures. There are many structures 100 years old that have not failed or, more likely, have had component replacement of significant maintenance prior to the period of this data set. The oldest structure found in the current work notification database is 99 years old, and the oldest structure found in the current inventory database is 102 years old, so the structures with failures are considered to reasonably cover the entire age range.

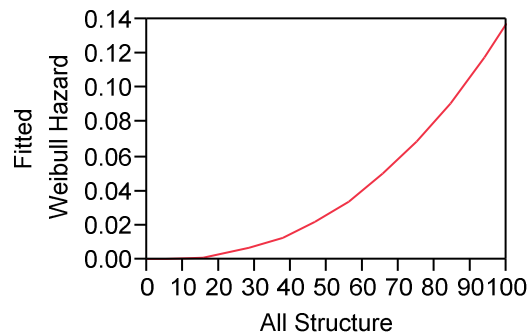


Figure 10-3. Fitted Weibull hazard function for structures

As shown in Figure 10-3, the typical failure rate of a structure increases with its age. Based on the fitted Weibull distribution, the typical failure rate of a structure of age 90 is around 0.11.

10.2 By Voltage

The matched structure work notifications are categorized into different voltage levels: 115kV, 230kV, 500kV. All the plots in this section utilize the legend below:

115kV —
230kV —
500kV —

The Kaplan Meier plots for structures in three different voltage levels are shown in Figure 10-4

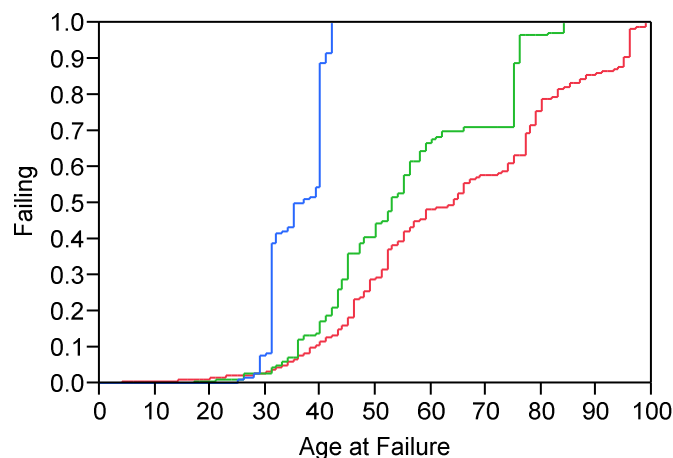


Figure 10-4. The Kaplan Meier plots of structures at different voltage levels

The Kaplan Meier plot for 500kV shows that all the work notifications of structures in 500kV systems are for those failed before the age of 42. From the Inventory database, the earliest installation year for 500kV structures is 1965. All the 500kV structures are installed



less than 55 years ago and the oldest failure record of a 500kV structure is at age 42. As a result, the algorithm does not see any failures occurring at older ages.

The estimates of Weibull distribution parameters are listed in Table 10-1:

Table 10-1. Estimates of Weibull distribution parameters for structures at different voltage levels

| Voltage Level | α | β | $f(x)$ |
|---------------|----------|---------|---|
| 115kV | 3.47 | 71.13 | $\frac{3.47}{71.13} \left(\frac{x}{71.13} \right)^{2.47} e^{-\left(\frac{x}{71.13} \right)^{3.47}}, x \geq 0$ |
| 230kV | 3.90 | 61.00 | $\frac{3.90}{61.00} \left(\frac{x}{61.00} \right)^{2.90} e^{-\left(\frac{x}{61.00} \right)^{3.90}}, x \geq 0$ |
| 500kV | 9.05 | 37.81 | $\frac{9.05}{37.81} \left(\frac{x}{37.81} \right)^{8.05} e^{-\left(\frac{x}{37.81} \right)^{9.05}}, x \geq 0$ |

The fitted Weibull probability density functions for structures at different voltage levels and their corresponding survive curves are shown in Figure 10-5a and 10-5b, respectively.

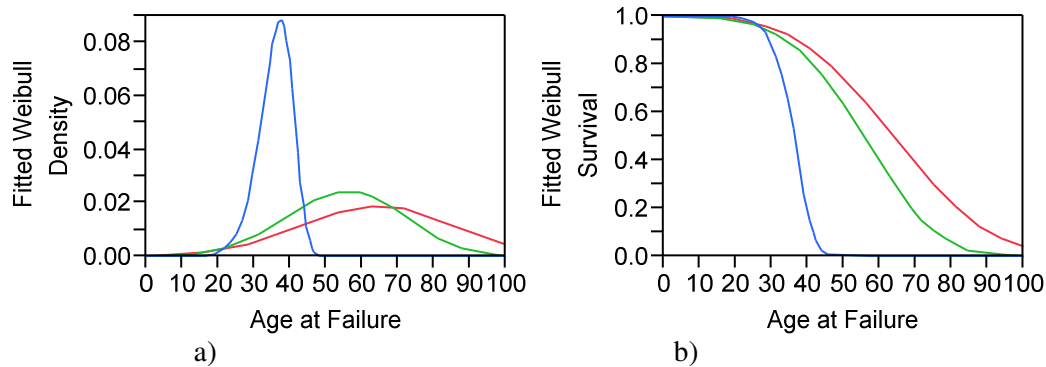


Figure 10-5. Fitted Weibull probability density functions and survival curves for structures at different voltage levels

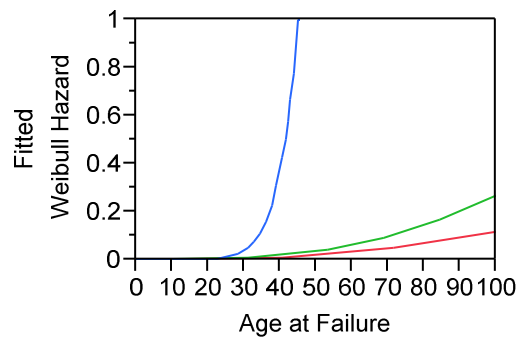


Figure 10-6. Fitted Weibull hazard function for structures at different voltage levels.

The pattern of structure failure in 500kV system is significantly different from the other two voltage levels. Because we are only looking at data for failed structures, the data implies that all 500kV structures would be expected to fail by age 45. This leads to a meaningless 500kV Weibull hazard plot which cannot be compared with the other voltages.

Between the structures of 115kV system and 230kV systems, it is shown in Figure 10-5 that the structures in 115kV systems tend to fail at a later age than 230kV systems; and it is shown in Figure 10-6 that beyond age 40, the failure rates of 230kV structures is roughly twice as high as 115kV structures.

10.3 By Damage Type

Among the 5,922 matched structure work notifications, 784 records have damage information which is grouped into five categories: Buckled/Bent, Corroded, Leaning, Rusted, Worn/Aged. In the sub-dataset of 784 records, there is only 1 record of structure damaged due to leaning and 9 records of structure damaged due to corrosion. The age of the 9 structures damaged due to corrosion are concentrated in the range of 38 – 52. In order to achieve representative results, the analysis here includes three damage type categories that have sufficient number of records: Buckled/Bent, Rusted, and Worn/Aged, 774 records in total. There are only 12 records of structures damaged due to Worn/Aged, but its age spreads out basically the entire age range (from 34 to 98), so this category is still kept in the study.

All the plots in this section utilize the legend below:

Buckled/Bent —
Rusted —
Worn/Aged —

The Kaplan Meier plots for structures of different damage types are shown in Figure 10-7.

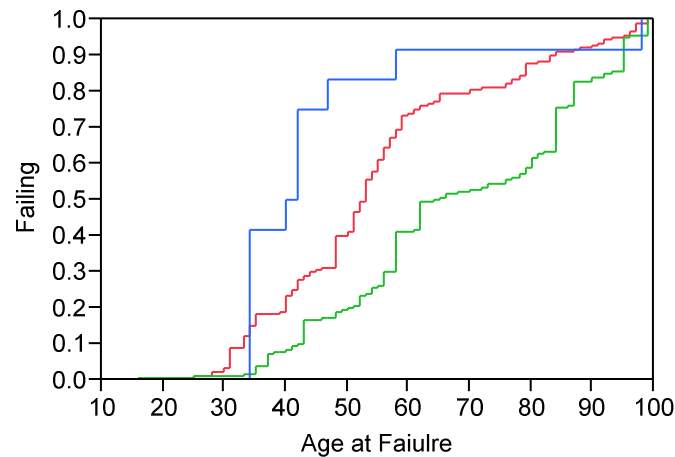


Figure 10-7. The Kaplan Meier plots of structures of different damage types

Due to the limited quantity of records related with structures damaged due to Worn/Aged, its curve in the Kaplan Meier plot has several obvious step-functions like zigzags. It can be a discrete version of a smooth curve, or it can be a biased curve due to biased data sample. Without additional information, the true underlying curve is not able to be identified. Therefore, special attentions should be taken to understand the results from this analysis related with the category of “Worn/Aged”.

The estimates of Weibull distribution parameters are listed in Table 10-2:

Table 10-2. Estimates of Weibull distribution parameters for structures of different damage types

| Type | α | β | $f(x)$ |
|--------------|----------|---------|---|
| BUCKLED/BENT | 3.17 | 61.39 | $\frac{3.17}{61.39} \left(\frac{x}{61.39} \right)^{2.17} e^{-\left(\frac{x}{61.39} \right)^{3.17}}, x \geq 0$ |
| RUSTED | 3.96 | 75.79 | $\frac{3.96}{75.79} \left(\frac{x}{75.79} \right)^{2.96} e^{-\left(\frac{x}{75.79} \right)^{3.96}}, x \geq 0$ |
| WORN/AGED | 2.58 | 50.51 | $\frac{2.58}{50.51} \left(\frac{x}{50.51} \right)^{1.58} e^{-\left(\frac{x}{50.51} \right)^{2.58}}, x \geq 0$ |

The fitted Weibull probability density functions for structures of different damage types and their corresponding survive curves are shown in Figure 10-8a and 10-8b, respectively.

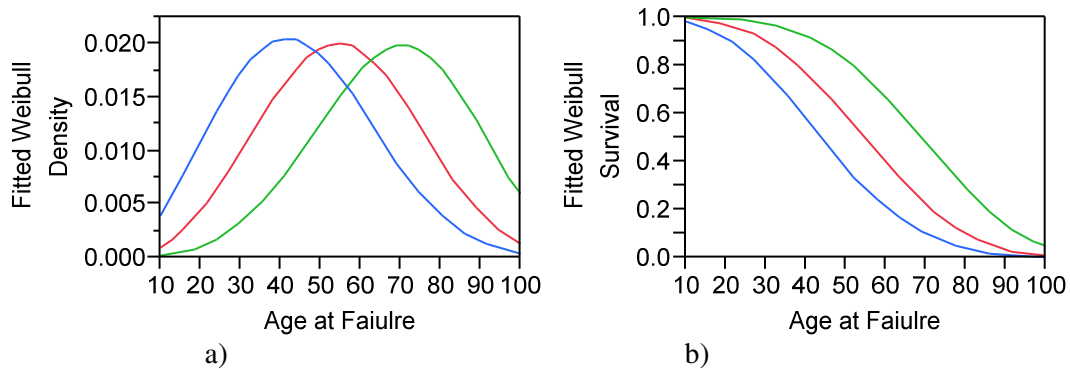


Figure 10-8. Fitted Weibull probability density functions and survival curves for structures of different damage types

According to the plots above, structures fail more at earlier age due to “Worn/Aged” than “Buckled/Bent”, and structures fail more at earlier age due to “Buckled/Bent” than “Rusted”. The most frequent age of structure failures due to “Worn/Aged” occurs around the age of 40, and the most frequent age of structure failures due to “Buckled/Bent” occurs around the age of 55, and the most frequent age of structure failures due to “Rusted” occurs around the age of 75.

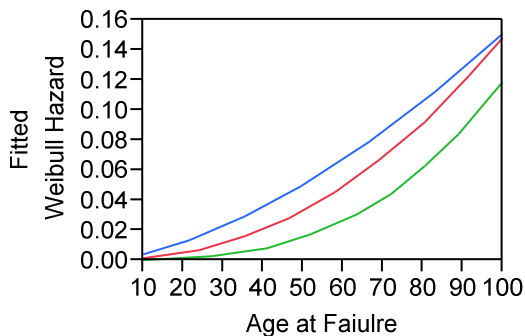


Figure 10-9. Fitted Weibull hazard function for structures with different damage types.

As shown in Figure 10- 9, the failure rate of structures due to “Worn/Aged” is constantly higher than the other two damage types; the failure rate of structures due to “Buckled/Bent” is slightly smaller than worn structures and the difference gets smaller at older ages. The failure rate of structures due to “Rusted” is smaller than the other two damage categories at all ages.



10.4 By Location

The matched structure work notifications are in three different locations: Coastal, Mountain, Valley. Among 5,922 matched work notifications, there are 796 records able to identify the location information: 231 records from the coastal region, 40 records from the mountain region, and 525 records from the valley region.

All the plots in this section utilize the legend below:

Coastal —
Mountain —
Valley —

The Kaplan Meier plots for structures of different types are shown in Figure 10-10.

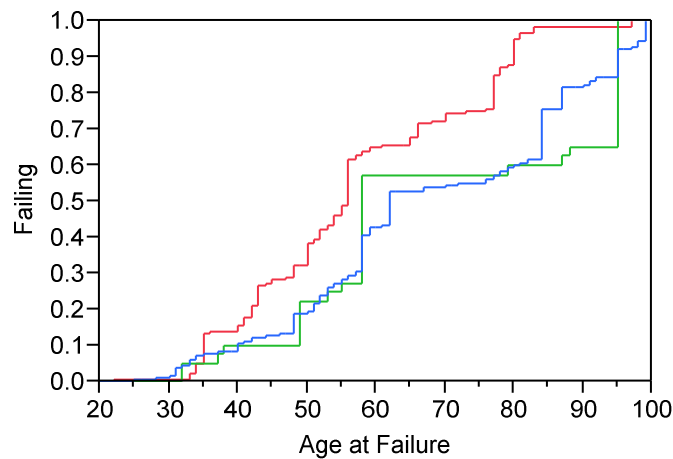


Figure 10-10. The Kaplan Meier plots of structures in different locations

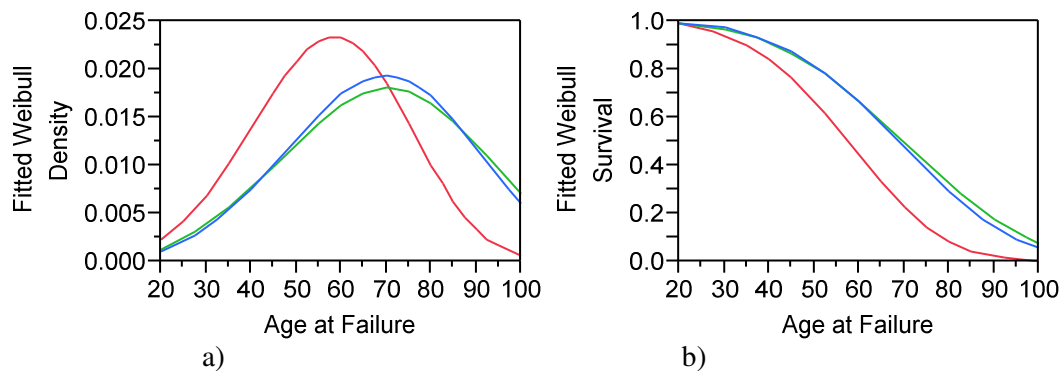
Even though only 40 records of structure failure in the mountain region are suitable for this particular regional analysis, the failure age of structures in the mountain region spreads out basically the same age range as the other two regions, the representativeness of results for the mountain area structure can be considered as sufficient regardless its limited historical data.

The estimates of Weibull distribution parameters are listed in Table 10-3:

**Table 10-3. Estimates of Weibull distribution parameters for structures in different locations**

| Type | α | β | $f(x)$ |
|----------|----------|---------|---|
| COASTAL | 3.87 | 63.27 | $\frac{3.87}{63.27} \left(\frac{x}{63.27} \right)^{2.87} e^{-\left(\frac{x}{63.27} \right)^{3.87}}, x \geq 0$ |
| MOUNTAIN | 3.63 | 77.18 | $\frac{3.63}{77.18} \left(\frac{x}{77.18} \right)^{2.63} e^{-\left(\frac{x}{77.18} \right)^{3.63}}, x \geq 0$ |
| VALLEY | 3.84 | 75.73 | $\frac{3.84}{75.73} \left(\frac{x}{75.73} \right)^{2.84} e^{-\left(\frac{x}{75.73} \right)^{3.84}}, x \geq 0$ |

The fitted Weibull probability density functions for structures in different locations and their corresponding survive curves are shown in Figure 10-11a and 10-11b, respectively.

**Figure 10-11. Fitted Weibull probability density functions and survival curves for structures in different locations**

It can be seen that the patterns of structures in the valley region and the mountain region are similar, while the pattern of structures in the coastal region is different from the other two locations. The structures in the coastal region tend to fail at younger ages and its peak age for failure is about 60, while the peak ages for structures in other regions are around 70.

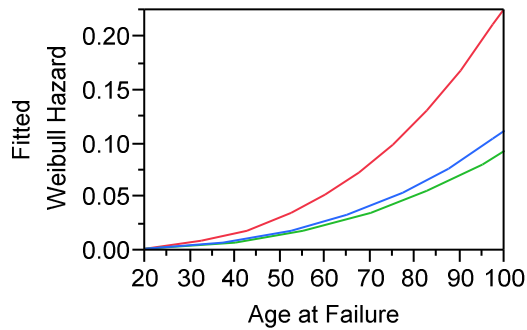


Figure 10-12. Fitted Weibull hazard function for structures in different locations.

As shown in Figure 10-12, the failure rate of structures in the coastal region is significantly higher than the failure rates of structures in the valley and mountain regions, with a rough ratio of 2:1. The structure failure rates in the valley and mountain regions are similar until the age of around 55; and then the failure rate of structures in the valley region are slightly higher than that of structures in the mountain region.

10.5 Summary

This review of failed structure data gives insights into the relative failure patterns of transmission structures on the PG&E system. It is based on fitting Weibull distributions to the failure data sets. This analysis is only based on reported failures from 2004 to 2008 and only for structures whose installation dates could be determined. (A complete failure analysis would have to include all past failures as well as data on the whole population of structures without failures. This is beyond the scope of this project and sufficient data probably does not exist.)

All Structures

Considering all reported failures, the highest numbers of failures occurred for structures around sixty years old. There are fewer reported failures for younger structure ages, as would be expected, but because there are fewer older structures there are also fewer failures occurring at ages greater than 60.

By Voltage

When considering the three primary transmission voltages, the structures for 500kV have not been in service nearly as long as those for 230kV and 115kV and all reported failures are for structures less than 45 years old. As explained in the report the Weibull analysis does not lead to meaningful comparisons of 500kV with the other two voltages. However, the 230kV and 115kV structures were experiencing the highest number of failures for structure ages 60 years and 70 years respectively. The data analysis also suggests that during the 2004-2008



time period that 230kV structures were experiencing failures at about twice the rate as for 115kV structures for all ages.

By Damage Type

In comparing the three dominant damage categories,

- Worn/Aged
- Buckled/Bent
- Rusted

Worn/Aged is reported most frequently and at younger ages, Rusted is reported at the lowest rate and occurs at older ages, and Buckled/Bent is in the middle both in frequency and age.

By Location

The final comparison was based on the region where the structures were constructed,

- Coastal
- Valley
- Mountain

Structures in the Coastal region experienced failures earlier in life (peaking before 60) than in the other two regions and also had about twice the failure rate at all ages. The ages of failures for the Valley and Mountain regions (peaking around 70) as well as their failure rates were fairly similar to each other.

It should be noted that because only limited data could be analyzed that the Weibull hazard plots in this report do not display actual failure rates. Rather, the plots show relative differences in the failure rates among the various categories.

11 Conclusions and Strategies

Inspection, repair, and refurbishment of steel structures and associated components (guys, anchors, foundations, etc.) are a critical part of the ongoing maintenance and management of the transmission infrastructure. Normal aging and deterioration, coupled with years of inadequate inspection and maintenance, put many structures at a point of less than desired structural integrity. While catastrophic failure of structures remains infrequent in the industry, it is a risk that has asset managers continually concerned, especially with older systems.

Maintenance strategies for structures and associated components typically consist of visual inspections as part of the overall transmission line inspection process. This process includes periodic line patrols, aerial or flying inspections, and climbing inspections. Each type of inspection is



scheduled to a predetermined frequency, often based on budget and manpower constraints. This inspection process is typical of electric utility companies. Inquiries with other tower owners, primarily communications companies, revealed that the electric industry is far beyond others in planned maintenance for tower infrastructure.

Recently some utility companies, in recognition of the risk of age related deterioration, have begun to use more diagnostic testing methods as part of the structure inspection and assessment. These methods are intended to inform the company of additional risks that may be present due to stray voltages and cathodic reactions, corrosion of below grade tower members due to coating deterioration and/or corrosive soil conditions, and other issues that are not recognized in the course of a visual inspection. These diagnostic methods are not widely used for routine inspection but often are only applied when presence of a problem is known or strongly suspected from other inspections or events.

A comprehensive maintenance and inspection program for an aging structure population should include a diagnostic testing component, particularly when structures reach an age threshold that is appropriate. That threshold varies by many factors: geographic location and associated environmental conditions, age of infrastructure, proximity to other infrastructure, historical performance of similar vintage structures in the company, etc. These variables are some of the inputs to an asset management strategy that is specific to the company and its environment.

Because the predominant practice in the industry for management of structures is to repair or refurbish structures and components, a strategy that can effectively determine component condition and the risk the condition represents to the overall structure integrity should be implemented. The question of repair, refurbish, or replacement of a structure is largely an economic decision dependent upon the degree of deterioration or damage present. However, the long expected service life of structures, the durability of the materials, and the ability to replace parts of a structure or reinforce a foundation, drive a predominant philosophy of repair or refurbish. The industry's current ability to perform structure repairs (and even replacement) while the circuit remains energized also lends itself toward repair of components as opposed to full replacement.

An effective strategy for structure and foundation management would include elements such as:

- Routine visual inspections by ground patrol and aerial patrol as part of general line inspection process,
- Comprehensive climbing inspection at 3-5 year intervals,
- Measurement of coating thickness at intervals of approximately ten years,
- Recoating or painting at intervals determined by the degradation of the coating thickness (industry data indicates 15-20 years),



- Diagnostic testing of below grade steel components at intervals determined by company experience and statistical sampling (initial testing at 15-20 yrs. dependent upon harshness of environment, interval to be determined thereafter),
- Laboratory testing of components removed from service as part of repair or replacement work to determine overall condition and remaining strength of material.

These program elements represent the framework of a comprehensive maintenance strategy for structures and associated components. The intervals are highly variable dependent upon the conditions in which the structure is placed. Coastal environments or areas with industrial pollution are common examples of locations where the chemical deterioration of the structure is likely to be much faster than a dry, rural environment. Records of historical performance and comparative test values within each company's environment are the critical inputs to the determination of intervals for inspection and testing. For a population of structures and foundations such as exists at PG&E, the leading criterion for determining inspection and testing targets, would initially be age. With a structure population age span of over 100 years (according to inventory records), a programmed sampling of the population over 80 years of age to test structure and foundation integrity would be an appropriate beginning.



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EXHIBIT G

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Pacific Gas and Electric Company) **Docket ER16-2320-002**

PREPARED REBUTTAL TESTIMONY OF

KEVIN J. DASSO

EXHIBIT NO. PGE-0037

October 9, 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company) Docket No. ER16-2320-002

Summary of the Prepared Rebuttal Testimony
of
KEVIN J. DASSO

Mr. Dasso's rebuttal testimony (Exhibit No. PGE-0037) responds to assertions by Ms. Geneva Looker on behalf of the California Public Utilities Commission (CPUC). Mr. Dasso's testimony explains that the goals for PG&E's electric transmission capital expenditures are to provide safe and reliable electric system operations, meet regulatory compliance requirements, modernize the system to support California's clean energy policy goals, and execute work requested by others. Mr. Dasso explains that PG&E makes these investments to address deteriorating electric system infrastructure and to address equipment that has reached the end of its useful life and system designs that no longer meet operational requirements.

Mr. Dasso also responds to Ms. Looker's assertions that PG&E's "self-approved" projects. --Projects that are not included in the California Independent System Operator Corporation (CAISO) Transmission Planning Process (TPP),-- are not just and reasonable. Mr. Dasso disagrees with this assertion and provides information about how PG&E provides transparency for external stakeholders about proposed projects through data request responses submitted in rate cases.

Mr. Dasso also explains that the Commission clearly held that PG&E was not required to have its own separate Order No. 890 compliant stakeholder process for its projects that do not go through CAISO stakeholder processes. The primary focus of Order No. 890 was to ensure non-discriminatory open

access to transmission. PG&E believes that the Commission's objectives in issuing Order No. 890—for coordination, openness, and transparency—are fully met by the planning and stakeholder engagement processes conducted by the CAISO today.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Pacific Gas and Electric Company) **Docket ER16-2320-002**

PACIFIC GAS AND ELECTRIC COMPANY
EXHIBIT NO. PGE-0037

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GLOSSARY OF ACRONYMS

| | |
|--------------------|--|
| ACOD: | Average Circuit Outage Duration |
| ACOF: | Average Circuit Outage Frequency |
| BAAH: | Breaker-and-a-Half |
| CAISO: | California Independent System Operator Corporation |
| CPUC: | California Public Utilities Commission |
| DBSB: | Double-Bus-Single Breaker |
| ET: | Electric Transmission |
| FERC or | |
| Commission: | Federal Energy Regulatory Commission |
| GIDAP: | Generation Interconnection and Deliverability Allocation Procedures |
| IPP: | Integrated Planning Process |
| kV: | Kilovolt |
| LOBs: | Lines of Business |
| MW: | megawatt |
| NCPA: | Northern California Power Agency |
| NERC: | North American Electric Reliability Corporation |
| PG&E or | |
| Company: | Pacific Gas and Electric Company |
| PTO: | Participating Transmission Owner |
| RIBA: | Risk Informed Budget Allocation |
| RTO: | Regional Transmission Organization |
| SAIDI: | System Average Interruption Duration Index |
| SCADA: | Supervisory Control and Data Acquisition |
| SCE: | Southern California Edison Company |
| SDG&E: | San Diego Gas & Electric Company |
| T&D: | Transmission and Distribution |
| TO: | Transmission Owner |
| TO18: | PG&E's Eighteen Transmission Owner Rate Case |
| TPP: | Transmission Planning Process |
| TRR: | Transmission Revenue Requirement |
| WRO: | Work at the Request of Others |

1 Q 16 Why does PG&E approve replacement and reconfiguration projects
2 outside of the CAISO's Transmission Planning Process (TPP)?

3 A 16 The CAISO's TPP focuses on expansion of the ET system under its
4 control to accommodate changes in demand and energy supply and
5 to meet reliability standards. The CAISO's TPP does not review
6 replacement of existing equipment and facilities for reasons other
7 than expanding the capacity of the transmission system or meeting
8 reliability standards. PG&E has two key areas of investment in
9 existing equipment replacement or reconfiguration projects in the
10 PG&E's eighteenth Transmission Owner (TO18) rate case:
11 (1) replacing aging and deteriorating infrastructure; and (2) improving
12 the ET grid reliability by bringing legacy systems up to current PG&E
13 design standards. Much of PG&E's existing infrastructure was built
14 decades ago. For transmission substations, historical bus designs
15 such as the Double-Bus-Single Breaker (DBSB) or single bus
16 configurations have been found to be less reliable and resilient than
17 the current industry best practice bus design standard of Breaker-
18 and-a-Half (BAAH) or ring bus designs.

19 Q 17 What is the average age of some of PG&E's ET assets compared to
20 their expected service life?

21 A 17 The average age of single phase substation power transformers is
22 about 38 years, with approximately 237 units older than 30 years or
23 almost half the entire transmission transformer fleet. The expected
24 service life of transmission system transformers is around 50 years,
25 but the industry average age of failed transformers is around
26 25 years. The average age of transmission steel towers is 68 years
27 with the oldest structure at 108 years. The design service life for
28 steel towers is 65 years.

29 Q 18 When did PG&E start upgrading its legacy bus design?

30 A 18 PG&E began a programmatic review of its substation bus designs in
31 2003, proposing bus upgrades when warranted. Prior to 2003,
32 PG&E's typical bus configuration was a single bus or DBSB design.
33 Past outages have shown these legacy configurations to be less

1 reliable in that single failures have led to outages of large portions of
2 the substation and, in some cases, the entire substation. PG&E has
3 implemented alternatives to the BAAH conversions, namely in the
4 sectionalizing of existing DBSB systems. Sectionalizing the DBSB
5 systems limits impacts to a single bus section instead of the entire
6 bus, but can still have significant adverse impacts on transmission
7 system reliability during an unplanned event.

8 Q 19 Are the projects which are planned or prioritized outside of the CAISO
9 planning process prudent?

10 A 19 Yes. Replacement of deteriorating equipment is prioritized by a data
11 driven, condition-based methodology. This methodology takes into
12 account system safety for public and employees, system criticality,
13 customer impact, age, health, maintenance records and inspection,
14 operational difficulties, sampling results such as oil or gas analysis,
15 lack of spare parts, manufacturer service advisories, and restoration
16 plans. Upgrade of existing bus systems are prioritized in three key
17 categories: reliability based on historical customer outages;
18 functionality based on current operational constraints; and criticality
19 based on system resiliency needs to minimize large disruptions.

20 **F. The CPUC Witness, Geneva Looker, Misrepresents PG&E's Budget**
21 **Development Process**

22 Q 20 Does CPUC witness Ms. Looker offer an inaccurate description of
23 PG&E's transmission capital budget development process?

24 A 20 Yes. In Exhibit No. PUC-0001, on lines 1 and 2 of page 42,
25 Ms. Looker states that she found verification that PG&E plans around
26 a set budget, rather than fixing the budget based upon needs. Also
27 on lines 18 to 21 of page 42 she suggests that PG&E's transmission
28 capital budget is set first and then projects are chosen up to that cap
29 and concludes that PG&E gives itself leeway to invest whatever it
30 wants, with no controls except for the viability of the Company itself.

1 Q 21 Do you agree with these statements?

2 A 21 No. Ms. Looker's understanding of and conclusions with respect to
3 how PG&E develops the transmission capital expenditures budget
4 are incorrect. Section D of my rebuttal testimony provides PG&E's
5 transmission investment goals while Section E explains the inputs
6 and weighing factors used in ranking the assets in order to identify
7 the transmission system needs. My testimony below will explain how
8 the transmission capital budget is developed.

9 Q 22 Please provide an overview of PG&E's assessment of needs and
10 how it informs the budget development process and the prioritization
11 of projects?

12 A 22 PG&E assesses its system needs first and develops the capital
13 investment budget based on that assessment. For ET, PG&E first
14 performs an assessment on ET system performance and then
15 prioritizes projects based on identified performance needs. The list of
16 needs is typically longer than the resources available to address
17 those needs. With that list of needs, and similar lists from other lines
18 of business (LOB), PG&E senior management sets overall Company
19 budget targets and then sets individual LOB budgets through the
20 integrated planning process (IPP).

21 Q 23 How did PG&E develop the portfolio of projects included in this
22 eighteenth TO Tariff filing (TO18)?

23 A 23 As part of the capital forecast and work execution planning
24 processes, PG&E developed a multi-year investment plan that
25 encompasses the capital projects listed in the TO18 filing. The multi-
26 year planning process is cyclical and incorporated into PG&E's IPP.

27 Q 24 How does PG&E measure and prioritize projects based on risk?

28 A 24 In 2014, PG&E introduced the Risk Informed Budget Allocation
29 (RIBA) framework to evaluate and prioritize the work portfolios for the
30 core operational LOBs. Those core LOBs are: Electric Operations,
31 Gas Operations, and Power Generation (including Nuclear

EXHIBIT H



United States
Department of
Agriculture

Forest
Service

Plumas
National
Forest

159 Lawrence Street
Quincy, CA 95971-6025
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File Code: 2360

Date: March 13, 2019

Julianne Polanco
State Historic Preservation Officer
Office of Historic Preservation
Department of Parks and Recreation
1725 23rd Street, Suite 100
Sacramento, CA 95816-7100

Dear Ms. Polanco,

The Pacific Gas and Electric Company (PG&E) is proposing significant modifications to an electrical power line system, collectively referred to as the Caribou-Valona Transmission Corridor, which it owns and operates in Northern California. PG&E is currently rectifying height discrepancies along numerous selected tower spans to meet standards set by California Public Utilities Commission General Order 95 and North American Electric Reliability Corporation (NERC) requirements. A portion of this expansive system includes the historic 1921 Caribou-Big Bend 115 kV Transmission Line which is itself part of what is identified by PG&E as the larger Caribou-Palermo Transmission Line segment. The historic Caribou-Big Bend Transmission Line passes through the Feather River Canyon within the Plumas National Forest (Forest) in Butte and Plumas counties. PG&E's electrical transmission and distribution facilities located on agency administered lands are operated and maintained through special use permit, easement, lease, or other authorizations issued by Forest Service. PG&E's operations and maintenance activities authorized by the Forest Service are subject to Section 106 of the National Historic Preservation Act of 1966, as amended, (NHPA) and its implementing regulations found within 36 CFR 800.

The Caribou-Big Bend 115 kV Transmission Line segment contains 314 structures (towers) over a total length of 38.2 miles and, as noted, is a section of the longer Caribou-Palermo 115 kV power line, which runs from the Caribou Powerhouse to the Palermo Substation. The planned NERC program repairs on the Caribou-Big Bend segment will address 105 towers, including the replacement of 60 original 1921 steel lattice towers with new tubular steel pole H-frame structures on micropile foundations. In addition, reconductoring will occur at 21 towers while conductors will be re-tensioned and hardware replaced on another 25 towers. Due to the steep terrain and lack of existing roads to structures, access will be provided primarily by helicopter. To support the work, PG&E has requesting authorization to use 8 helicopter landing zones and/or staging areas to install 13 temporary helicopter landing platforms for crew access, and to use 10 areas for conductor pull sites during reconductoring.

Two separate reports addressing Section 106 compliance have been prepared by contractors for PG&E including an archaeological survey report submitted to the Forest in December of 2018 designed to meet the requirements of the *First Amended Programmatic Agreement Among the*



U.S.D.A. Forest Service, Pacific Southwest Region (Region 5), California State Historic Preservation Officer, Nevada State Historic Preservation Officer, and the Advisory Council on Historic Preservation Regarding the Process for Compliance with Section 106 of the National Historic Preservation Act for Management of Historic Properties by the National Forests of the Pacific Southwest Region – 2018 (PA). The survey report indicates that the proposed Caribou-Big Bend NERC Project, including all landing zones, staging areas and pull sites, will avoid all recorded archaeological and cultural properties utilizing standardized protection measures outlined in Appendix E of the 2018 PA. This will be reported within the Forest's 2019 PA Annual Report. The second report addressing Section 106 compliance for the Project is focused on the historic status of transmission line itself. This second effort is the basis for the present consultation.

Please find enclosed a report prepared by Stephanie Cimino and Wendy Nettles of PG&E, and updated by Polly Allen of Cardno, Inc. (October, 2018) for your review. Ms. Allen's update is a response to information provided by the Forest responding to the initial draft report provided by Cimino and Nettles (April 2017) which made a recommendation that the Caribou-Big Bend 115 kV Transmission Line segment in the Feather River Canyon did not meet criteria for listing on the National Register of Historic Places (NRHP). The Forest contended that this pioneering transmission line was historically significant and submitted a report, authored by Daniel Elliott and Jamie Moore (Plumas National Forest), to PG&E in January of 2018. This report presented an argument for a finding of historic significance under Criterion A and C (36 CFR 60.4). The final updated report revised updated by Allen does make a recommendation of significance under Criterion A but continued to argue against a finding of significance under Criterion C.

Another point of contention was PG&E's methodology in which it defined historic era transmission lines by their current and/or modern operating configuration rather than highlighting the manner in which they were historically developed; obfuscating the potential period of significance and the unique context that might be associated with an individual line. Elements of the larger Caribou-Valona Transmission Corridor are of much more modern derivation and are also far outside the confines of the Forest. Therefore, although the provided report addresses multiple transmission lines over a large geographic area, the Forest is addressing only the historic Caribou-Big Bend 115 kV Transmission Line which is a distinct operational entity and a singular linear historic era cultural resource (site) that is located primarily on USFS administered lands.

The Forest is requesting your review of the enclosed report as it pertains to the historic Caribou-Big Bend 115 kV Transmission Line and, as per 36 CFR 800.4.(c)(1-2), concurrence for our finding that the 1921 transmission line is eligible for inclusion in the NRHP under Criterion A for its association with key historical events and trends in the development of long-distance hydroelectric transmission lines in California. The Feather River Canyon "Mountain" segment, developed by the Great Western Power Company from Caribou Powerhouse (already found individually eligible for the NRHP) to the Big Bend Substation, retains sufficient integrity to convey the significance of its regional contextual and physical development, with overall integrity of materials, workmanship, design, setting, feeling, association, and location evident in the alignment's overall design and engineering. The Forest is further requesting your

concurrence that the proposed NERC Project will have an adverse effect to this same historic property as per 36 CFR 800.5(a)(2)(i), and that further compliance with Section 106 will be required under 36 CFR 800.6 to resolve this adverse effect.

Tribal Consultation was initiated by the Forest in August of 2018 on both the findings of the archaeological survey under the 2018 PA (data shared by PG&E prior to the delivery of the final draft survey report) and the finding of NRHP eligibility for the affected transmission line. There have been several subsequent meetings and one field visit with tribal members but no issues have been identified regarding the historic significance of the line itself.

Given that the question of the Caribou-Big Bend 115 kV Transmission Line's historic significance has taken an extended period of time to be resolved and with the approach of fire season in this critical area, the Forest is requesting an expedited review and concurrence with our findings for this undertaking. If you have any questions or require any additional information, please contact Daniel Elliott, Plumas National Forest Heritage Program Manager/Forest Archaeologist at 530 283-7774, or email at delliott01@fs.fed.us. You may also contact Christophe Descantes, Senior Cultural Resources Specialist for PG&E at 415 973-1177 or email at chd8@pge.com.

Sincerely,


JERRY K. BIRD
Forest Supervisor

Enclosure

cc Christophe Descantes, Sr. Cultural Resources Specialist, PG&E

EXHIBIT I



**Pacific Gas and
Electric Company**

NERC Alert Project – Final Scope Review

Date: January 3, 2018

To: Leslie Edlund, Mt. Hough Ranger District, Plumas National Forest
Mary Sullivan, Feather River Ranger District, Plumas National Forest

CC: Paul Marotto, PG&E
Jeff Ward, Burns & McDonnell

Subject: **PG&E NERC Program – Caribou-Big Bend 115 kV Power Line (SAP Project #74000733) – Plumas and Butte Counties – PG&E Power Line Tower and Conductor Maintenance Work**

Purpose

This memorandum is prepared as notification to the USDA Forest Service, Plumas National Forest (Plumas NF) of maintenance activities on certain power line towers located in the Plumas NF under Pacific Gas & Electric Company's (PG&E's) *Operation and Maintenance Plan for Electric Transmission and Distribution Lines on the Plumas National Forest* (OMP). The following describes the scope of work, schedule, and environmental analysis of the proposed maintenance activities on the **Caribou-Big Bend 115 kV** power line circuit (SAP Project #74000733).

Background

PG&E is planning power line tower maintenance work on an electrical power line it owns and operates in the Plumas NF. PG&E is currently rectifying height discrepancies along certain tower spans of electric power lines to meet standards set by California Public Utilities Commission General Order (GO) 95 and to meet the requirements of the North American Electric Reliability Corporation (NERC), which is a part of the Federal Energy Regulatory Commission (FERC). The planned repair, maintenance, and replacement activities are required to elevate the conductor a sufficient distant above the natural ground surface to meet GO 95 standards.

One of the circuits PG&E is currently addressing is the **Caribou-Big Bend 115 kV** power line located near the North Fork of the Feather River, a portion of which occurs within Plumas NF (**see attached maps**). The existing circuit contains 314 structures over a total length of 38.2 miles. Caribou-Big Bend 115 kV is a section of the longer Caribou-Palermo 115 kV power line, which runs from the Caribou Power House to the Palermo Substation. PG&E presented NERC Program power line repair work to the Plumas NF at the US Forest Service-PG&E Annual Coordination Meeting on May 8, 2017; and then in more detail at a preliminary consultation meeting on November 8, 2017.

Scope of Work

The planned NERC Program repairs on the **Caribou-Big Bend 115 kV** power line addresses 87 towers, including replacing 49 steel lattice towers (see **Attachment A, photograph 1**) with tubular steel pole (TSP) H-Frame structures (**Attachment A, photograph 2**) on micropile foundations (**Attachment A, photographs 3-5**). At 29 towers, conductors and hardware will be replaced. At 28 towers, conductors would be re-tensioned and hardware replaced. Due to the steep terrain and lack of existing roads to structures, access and repairs on **Caribou-Big Bend 115 kV** would be conducted mostly by helicopter. To support the work, PG&E is requesting authorization to use 8 helicopter landing zones (LZs)/staging areas, install 13 temporary helicopter landing platforms for crew access (**Attachment A, photographs 6-8**), and use 10 areas for conductor pull sites during re-conductoring. Table 1 below summarizes the type of repair and location. Table B-1 in **Attachment B** lists the repair location, scope, and environmental avoidance and minimization measures (AMMs) to be implemented. Each repair activity is described in greater detail below.

Tower replacements. Tower replacements are planned due to age and type of the existing steel lattice towers. The existing towers are approximately 100 years old and are directly buried grillage with no concrete foundations. The towers are not considered structurally suited to the addition of lattice steel cage top, waist cage, or other extensions to raise the heights of the towers.

Most new TSP H-Frame structures would be installed 25 feet ahead or back from the center point of the existing 4-legged steel tower. This is the typical minimum offset distance to avoid undermining the foundation of the existing tower. Some towers will be replaced in the same footprint of the existing tower, or greater than 25 feet ahead or back, due to the suitability of the terrain within the easement. New TSP H-Frame structures would be delivered by truck to LZs for assembly, and then flown by helicopter to be installed on the micropile foundations (see below). Depending on the weight of the structures and type of helicopters, the entire H-Frame may be flown in pre-assembled or in sections.

After the new TSP H-Frame is installed, conductors would be transferred from existing towers to new structures. Old tower legs would be cut approximately 1 foot below grade, and the old towers flown by helicopter to the LZs for disassembly and disposal off site. Depending on the size of the helicopter, the old towers may be flown intact or in sections.

Micropile foundations. Due to the steep terrain and lack of road access to existing towers, standard concrete foundations - that require ground vehicles such as excavators and concrete trucks to install - are not considered feasible without creating an extensive new road network. Therefore, to avoid the extensive grading and ground disturbance required for standard concrete foundations, helicopter access and micropile foundations are planned. Micropile foundations are set atop piles drilled into bedrock. The exact size of each individual micropile foundation is based on the size of the TSP structure and type of bedrock. Typical foundations have 3-6 piles with 7-inch diameter casings at ground level, and are drilled 25-45 feet deep. The piles are grouted into the bedrock and then a circular base plate attached 1-2 feet above grade. New TSPs would be bolted to the top of base plates, which are 5½ feet to 7 feet in diameter.

The micropile drill rig is on a 4-legged steel table, 12 feet by 15 feet in size, and has 4 height adjustable legs to set up on uneven ground (**Attachment A, photographs 9-11**). The drill rig is flown in by helicopter. Most locations are in close enough proximity for the micropile foundation crews to drive vehicles on existing roads and then walk to foundation drill rigs. At more remote sites, PG&E is requesting authorization to install 14 temporary helicopter landing platforms to transport crew by helicopter for daily access. The platform is on a 4-legged table 8 feet by 8 feet in size, slightly larger than the helicopter skids. To set up the micropile drill rig and helicopter platform, approximately 4 SF of temporary ground disturbance and leveling is required to set up the adjustable table legs. In addition, clearing brush would be required to set the drill rig and landing platforms. At one location above tower :0/2 approximately 10-12 trees would also have to be cleared to create an opening for the helicopter landing platform.

Table 1. PG&E NERC Program Repairs, Caribou-Big Bend 115 kV

| Tower | APN | Ranger District | Type of Work | | | |
|----------|-----------|-----------------|-------------------|------------------------------------|--|---------------|
| | | | Tower Replacement | Conductor and Hardware Replacement | Conductor Re-tensioning and Hardware Replacement | Tower Removal |
| :0/1 | 002140USA | Mt. Hough | | X | | |
| :0/2 | 002140USA | Mt. Hough | X | X | | |
| :0/3 | 002140USA | Mt. Hough | | X | | |
| :0/4 | 002140USA | Mt. Hough | X | X | | |
| :0/5 | 002140USA | Mt. Hough | X | X | | |
| :0/6 | 002140USA | Mt. Hough | X | X | | |
| :0/7 | 002140USA | Mt. Hough | | X | | |
| :1/11 | 002140USA | Mt. Hough | X | | | |
| :2/19 | 002140USA | Mt. Hough | | | X | |
| :2/20 | 002140USA | Mt. Hough | X | | | |
| :2/21 | 002140USA | Mt. Hough | X | X | | |
| :3/22 | 002140USA | Mt. Hough | | X | | |
| :3/29 | 002140USA | Mt. Hough | X | X | | |
| :3/30 | 002370USA | Mt. Hough | | X | | |
| :4/31 | 002370USA | Mt. Hough | | X | | |
| :5/39 | 002370USA | Mt. Hough | X | | | |
| :5/40 | 002370USA | Mt. Hough | X | | | |
| :5/42 | 002370USA | Mt. Hough | X | | | |
| :6/51 | 002370USA | Mt. Hough | X | | | |
| :8/64 | 002230USA | Mt. Hough | X | | | |
| :8/65 | 002230USA | Mt. Hough | | X | | |
| :8/66 | 002230USA | Mt. Hough | X | X | | |
| :8/67 | 002230USA | Mt. Hough | | X | | |
| :8/68 | 002230USA | Mt. Hough | | X | | |
| :9/73 | 002220USA | Mt. Hough | | X | | |
| :9/74 | 002220USA | Mt. Hough | X | X | | |
| :9/75 | 002220USA | Mt. Hough | X | X | | |
| :9/76 | 002220USA | Mt. Hough | | X | | |
| :9/77 | 002220USA | Mt. Hough | X | | | |
| :10/83 | 002220USA | Mt. Hough | | X | | |
| :10/84 | 002220USA | Mt. Hough | X | X | | |
| :10/85 | 002220USA | Mt. Hough | X | X | | |
| :11/86 | 002220USA | Mt. Hough | | X | | |
| :11/87 | 002220USA | Mt. Hough | | X | | |
| :11/90 | 002220USA | Mt. Hough | X | | | |
| :11/91 | 002220USA | Mt. Hough | X | | | |
| :12/95 | 002220USA | Mt. Hough | X | | | |
| :13/105 | 002260USA | Mt. Hough | X | | | |
| :13/108 | 002260USA | Mt. Hough | | X | | |
| :13/110 | 002260USA | Mt. Hough | X | X | | |
| :14/110A | 002260USA | Mt. Hough | | | | X |
| :14/111 | 002260USA | Mt. Hough | X | | | |
| :14/116 | 002260USA | Mt. Hough | X | | | |
| :15/125 | 002260USA | Mt. Hough | X | | | |
| :16/128 | 002260USA | Mt. Hough | X | | | |
| :16/131 | 002260USA | Mt. Hough | X | | | |
| :16/132 | 002260USA | Mt. Hough | | | X | |
| :16/133 | 002260USA | Mt. Hough | X | | | |
| :16/134 | 002260USA | Mt. Hough | | | X | |

Table 1. PG&E NERC Program Repairs, Caribou-Big Bend 115 kV

| Tower | APN | Ranger District | Type of Work | | | |
|----------|-----------------|-----------------|-------------------|------------------------------------|--|---------------|
| | | | Tower Replacement | Conductor and Hardware Replacement | Conductor Re-tensioning and Hardware Replacement | Tower Removal |
| :16/135 | 002260USA | Mt. Hough | | | X | |
| :16/136 | 002280USA | Mt. Hough | X | | X | |
| :17/137 | 002280USA | Mt. Hough | | | X | |
| :17/137A | 002280USA | Mt. Hough | X | | X | |
| :17/138 | 002280USA | Mt. Hough | | | X | |
| :17/139 | 002280USA | Mt. Hough | X | | X | |
| :17/140 | 002280USA | Mt. Hough | | | X | |
| :18/151 | 002280USA | Mt. Hough | | | X | |
| :18/152 | 002280USA | Mt. Hough | X | | X | |
| :18/153 | 002280USA | Mt. Hough | X | | X | |
| :18/154 | 002280USA | Mt. Hough | X | | X | |
| :18/155 | 002280USA | Mt. Hough | | | X | |
| :21/178 | 002-290-014-000 | Mt. Hough | X | | | |
| :21/179 | 002-290-007-000 | Mt. Hough | | | X | |
| :23/195 | 058-790-004-000 | Feather River | | | X | |
| :23/196 | 058-790-004-000 | Feather River | X | | | |
| :24/197 | 058-790-004-000 | Feather River | | | X | |
| :24/198 | 058-790-004-000 | Feather River | X | | | |
| :24/202 | 058-790-004-000 | Feather River | X | | | |
| :24/204 | 058-790-004-000 | Feather River | X | | | |
| :25/205 | 058-790-004-000 | Feather River | | | X | |
| :25/206 | 058-790-004-000 | Feather River | | | X | |
| :25/207 | 058-030-009-000 | Feather River | X | | | |
| :25/210 | 058-030-009-000 | Feather River | | | X | |
| :25/211 | 058-030-009-000 | Feather River | X | | | |
| :27/225 | 058-070-037-000 | Feather River | X | | | |
| :27/227 | 058-070-037-000 | Feather River | | | X | |
| :28/228 | 058-070-037-000 | Feather River | X | X | | |
| :28/229 | 058-070-037-000 | Feather River | | X | | |
| :28/234A | 058-070-005-000 | Feather River | | | X | |
| :28/234 | 058-070-005-000 | Feather River | | | X | |
| :29/235 | 058-070-002-000 | Feather River | X | | X | |
| :29/236 | 058-070-002-000 | Feather River | | | X | |
| :31/252 | 058-780-007-000 | Feather River | | | X | |
| :31/253 | 058-780-007-000 | Feather River | | | X | |
| :31/254 | 058-780-007-000 | Feather River | X | | | |
| :31/257 | 058-170-047-000 | Feather River | X | | | |
| :33/267 | 058-170-049-000 | Feather River | X | | | |

Reconductoring. Working from 10 conductor pull sites on the ground under the easement, conductors would be replaced at 31 towers with reel trucks and bucket trucks. Replacing the conductor is required due to the age and condition of the existing conductor. The conductor does not have adequate strength to withstand the increased tension resulting from installing taller replacement structures.

Behind tower :0/1, an approximately 30-foot by 30-foot area would be cleared of brush and leveled using hand tools to set up conductor reels and pulling equipment. Reels and equipment would be flown in by helicopter, and pedestrian access is available to the crew on an existing foot path around the Caribou Power House. The other pull sites would be located on existing road crossings in the easement. Conductor reel trucks would be set up in the roads, and no land grading or road widening is expected to be required. Temporary road closures would be required during reconductoring in Butt-Ganser Road, Caribou Road, Howell Road, and Pulga Road. A traffic control plan will be prepared, and encroachment permits obtained from Plumas County, Butte County, and the Plumas NF, if required.

Schedule

Caribou-Big Bend 115 kV repairs would occur with multiple crews working continuously at multiple locations over a period of approximately 8 months in the latter part of 2019. Work is planned to begin in May 2019 for initial delivery and staging and assembly of materials at LZs and staging areas. Repairs on the power line itself would begin in May 2019. During the first day of the power line clearance, crews would access a switch at the Bucks Creek Tap (under span :18/150-:18/151) and clear the power line in the Bucks Creek to Big Bend Section, from tower :18/151 to tower :37/299. Electricity from the Caribou Power House would be transmitted via the Caribou-Table Mountain 230 kV transmission line. This lower half of the line, located mostly in Butte County, will be cleared from May through August 2019. With the lower half of the line cleared, crews would begin to move the middle conductor to the outside of existing towers, and fly and set micropile drill rigs at each tower replacement location.

May-August 2019, crews would install micropile foundations, TSP H-Frame structures, transfer conductors to new structures, and remove old towers. Work would focus on the LZs Rock Creek Penstocks, Rim Road at Concow Road, and Lower Rim Road. Additional LZs on private lands would also be used. New structures would be assembled and staged at the LZs, and then old towers would be disassembled and hauled away from the LZs by truck.

On August 31, 2019, the entire Caribou-Big Bend 115 kV power line would be cleared and the switch moved at Bucks Creek Tap to re-energize the lower half of the circuit and clear the upper section from Caribou Power House to Bucks Creek Tap (tower :0/1 to :18/140). The upper section of the line would be cleared August 31 through December 2019. Crews would then work from the LZs at Caribou Road, Lower Caribou Road, Belden Siphon, Plumas NF FR 26N26, and Belden Penstocks. Additional LZs on private lands would also be used. New structures would be assembled and staged at the LZs, and then old towers would be disassembled and hauled away from the LZs by truck.

Drilling micropile foundations requires 3-4 days of work per H-Frame structure. Grouting the piles takes a single day. Then after a minimum of 3 days for the grout to set, the foundations are tested and capped in 1-2 days of work. Setting a new TSP H-Frame structure on the new micropile foundations, transferring conductors from the old tower to the new structure, and then removing the old tower requires about 2 working days at each location.

Reconductoring requires approximately 5-7 days at each section, including 1 day to mobilize, 3-5 days to string new conductor, and 1 day to demobilize. Other repairs, such as replacing insulators and hardware and re-tensioning requires 1 day at each tower. Converting suspension towers to a dead-end configuration requires 2 days per tower.

EXHIBIT J

To: ebrenzovich@fs.fed.us[ebrenzovich@fs.fed.us]; mcsullivan@fs.fed.us[mcsullivan@fs.fed.us]
Cc: Burwell, Trevor [Trevor.Burwell@arcadis.com]; Trevor.Burwell@arcadis.com]; Thomas, Jennifer[j317@pge.com]; Cowgill, Mae (MUC5@pge.com)[MUC5@pge.com]
From: Marotto, Paul
Sent: Wed 10/18/2017 4:27:45 PM (UTC-07:00)
Subject: NERC Program - PG&E Caribou-Big Bend 115kV T/L - Plumas NF Pre-Notification Meeting Proposal

Erika and Mary,

If you recall, I briefly mentioned this project at our 5-8-17 Plumas NF / PG&E annual meeting. PG&E is planning maintenance to mitigate NERC discrepancies (ground to wire clearances) on approximately 38 miles of its Caribou-Big Bend 115kV T/L. This transmission line begins at PG&E’s Caribou No 1 Powerhouse (Plumas County) and runs approximately 38 miles in a southwesterly direction to PG&E’s Big Bend Switching Station (Butte County). A large portion of the transmission line is located within Plumas NF (Mt Hough and Feather River Ranger Districts).

PG&E’s planned maintenance includes structure replacement, conductor replacement, conductor re-tensioning, installation of new insulators and structure modifications. Within Plumas NF, PG&E plans to replace approximately 49 structures (37 Mt Hough / 12 Feather River district), replace conductor at approximately 35 structures (28 Mt Hough / 7 Feather River district), re-tension conductor at approximately 12 structures (10 Mt Hough / 2 Feather River district), install body modifications at 3 structures (Mt Hough district), and remove 1 structure (Mt Hough district).

PG&E is currently in the process of finalizing proposed access routes, siting landing zones, pull sites and staging areas. Due to the rugged terrain, complexity and size of this project; I would like to propose (if you are agreeable) a PG&E / Plumas NF pre-notification meeting. Attendees from PG&E would include Mae Cowgill (PG&E biologist), Jennifer Thomas (PG&E cultural resource specialist), Trevor Burwell (PG&E environmental consultant with Arcadis) and myself.

If you are agreeable to meeting with us, please provide 3 or 4 dates that work for both of you. For PG&E the sooner we meet the better as we would like to submit the notification Plumas NF within the next month. PG&E is available to travel to any of your offices for our meeting.

Thank you, Paul

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EXHIBIT K

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1 confirmation, that the procedures are actually being
2 followed, and to understand the type of data that is
3 available to the employees, and these strategy documents,
4 they don't really tell us where the data is, do they?

5 A Not necessarily. That's not the purpose of this
6 particular document.

7 Q Have you provided documents that would help us
8 identify where all the data is that PG&E would need to
9 implement any of its 1 to N strategies?

10 A Yes, we did. There were questions for the
11 databases -- does PG&E have information about its assets,
12 and we provided responses to data requests that asked for
13 that.

14 Q You provided lists of databases, but we did not
15 get the data, did we?

16 A That I don't know, but we provided the answer to
17 the question where are the databases, what are the
18 databases that are relevant.

19 Q How would a staff person know where to go to
20 find the appropriate data?

21 A A PG&E staff person?

22 Q A PG&E staff person that needs to run this
23 analysis, how would they find it?

24 A They would go to that particular database and
25 identify what needs to be pulled out of that database.

1 Q It would all be in one database?

2 A Not in all cases. I said that. Where we have
3 it, there's information -- again, for many of the asset
4 classes, the data is available and is in databases, and we
5 can provide those reports and we've done that.

6 Q PG&E doesn't have all of the data on a class of
7 assets in one place, does it?

8 A No. That doesn't mean it's not available and
9 can't be pulled together.

10 Q How does a PG&E staff person know where to look
11 for each piece of data that they need in order to run the 1
12 to N analysis?

13 A It depends on the asset class, and each of those
14 engineers are familiar with the data that is available to
15 them. They know where to find it. They also know that not
16 all of the data is exactly perfect.

17 However, they know, as we've provided in
18 responses to data requests, the age of substation
19 transformers, for example. That information is available.
20 It's readily available. The engineers that work in that
21 space have that information available to them, and they use
22 that regularly in their criteria or in their implementation
23 of the replacement criteria.

24 Q A PG&E engineer, program manager who's working
25 on a specific asset class will simply know where to find

1 the data to run the 1 to N analysis?

2 A Yes.

3 Q It's not written down anywhere?

4 A What do you mean not written down anywhere, the
5 precise directions to that engineer, exactly how to do
6 that?

7 Q A listing of where all the data is available for
8 a particular asset class. It's not identified, so if that
9 project manager gets hit by a bus, somebody else can run
10 the analysis? Are there no procedures in place at PG&E to
11 have this information shared and ensure that the analysis
12 that is run looks at all the data and not just selective
13 data?

14 A In some cases, we have procedures that lay that
15 out in some detail, and in other cases we do not. We do
16 not have in all cases the exact cookbook instructions for
17 how an engineer precisely does his job to produce the
18 information necessary to create the recommendations.

19 However, that's what we expect our engineers to
20 do. They understand the assets. They understand PG&E.
21 They understand where the data is. They understand how
22 it's labeled, how it's culled out. They also understand
23 where data may not be available for a particular class of
24 assets. PG&E is made up of many individual utilities that
25 have been acquired over the years.

1 The data available for each of those individual
2 utilities varies, so the engineers know that as they learn
3 about that particular asset so they know what to do in that
4 situation if they encounter that data that is not as
5 readily available as they might like it to be.

6 Q When was the last time that PG&E acquired assets
7 from another utility?

8 A We acquired distribution assets in 2014.

9 Q Transmission assets.

10 A I don't know off the top of my head. We
11 recently acquired some poles that were previously owned by
12 a small utility in the Sierras here about a year ago,
13 transmission poles.

14 Q Do you have a sense of how large that
15 acquisition was in the context of PG&E's network?

16 A That would be relatively small.

17 Q Has PG&E made any even medium-sized acquisitions
18 in the last 20 years for transmission assets?

19 A I'd say no. However, when the acquisition was
20 made, the records came over as they were. If we did not
21 have a need to gather certain types of data, we didn't
22 necessarily go out and gather that information. However,
23 we have been gathering that data recently and as referenced
24 in many of these strategy documents, there's additional
25 documents that we would like to gather and we're continuing

1 to do that. That doesn't mean we don't have the
2 information that we need in order to make the decisions
3 that are described in these strategies.

4 Q We're going to look at PG&E's response to CPUC
5 question 354, and we'll mark that as PUC-0070.

6 (Exhibit PUC-0070 identified.)

7 BY MS. BONE:

8 Q In that data request, the CPUC asked PG&E to
9 identify the location of the data used to implement each of
10 the strategies that PG&E has ultimately produced to us.

11 Are we there, 354?

12 A Yes, I have that.

13 Q And is it accurate to say that PG&E responded
14 that the data necessary to implement the strategies
15 provided in response to our question 224 and 235 are
16 detailed and PG&E's response to CPUC's questions 85, 86 and
17 87; is that correct?

18 A That's correct.

19 Q So now we're going to pull up the response to
20 question 85. And we're going to mark that as an exhibit.
21 That is going to be PUC-0071.

22 (Exhibit PUC-0071 identified.)

23 BY MS. BONE:

24 Q It describes the various databases used by PG&E.
25 Do you have it in front of you yet?