Application: 24-06-013
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Exhibit No.: PGE-02
Date: October 14, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

WILDFIRE RATE RELIEF BOND

ERRATA TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
WILDFIRE RATE RELIEF BOND
PREPARED TESTIMONY

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A. Introduction

Through this application,[1] Pacific Gas and Electric Company (PG&E) requests that the California Public Utilities Commission (CPUC or Commission) issue a financing order authorizing PG&E to finance up to $2.356 billion in costs and expenses related to catastrophic wildfires pursuant to Section 850(a)(2).[2] These costs and expenses, incurred in 2023-2024 and approved as just and reasonable in PG&E's 2023 General Rate Case (GRC) Decision, have contributed to increased wildfire mitigation costs in customer rates. The bonds will be used to provide immediate rate relief in the form of a rate credit to customers[3] and equitably distribute those costs over the life of the bonds. In this way, the proposed financing transaction (Wildfire Rate Relief Bonds) will help address affordability concerns and reduce the disproportionate rate impact on current customers for wildfire-related costs and expenses that provide wildfire mitigation benefits for future customers. The transaction also is financially neutral to PG&E and does not hinder PG&E's ability to fund critical wildfire safety or other utility work going forward. In addition, PG&E believes that, given a finite amount of securitized bonds that PG&E can issue to the market in any given year, this proposed issuance achieves the most bill relief for customers in the near term. Thus, PG&E's proposal is responsive to affordability concerns

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[1] For this and the other chapters of testimony, capitalized terms used, but not defined in the testimony have the meaning attributed in the application or other chapters of testimony.

[2] For this and the other chapters of testimony, unless otherwise noted, all references to "Section" are to the California Public Utilities Code (Pub. Util. Code).

[3] As used herein and in the remaining chapters of testimony, references to "customer" include the term "consumer" as defined in Section 850(b)(3) and as used in Section 850.1(b). See Pub. Util. Code § 850(b)(3) ("'Consumer' means any individual, governmental body, trust, business entity, or nonprofit organization that consumes electricity that has been transmitted or distributed by means of electric transmission or distribution facilities, whether those electric transmission or distribution facilities are owned by the consumer, the electrical corporation, or any other party.").

expressed by customers, intervenors, and other stakeholders in a manner that does not compromise safety or other important state policy goals.

This is PG&E's first application seeking to use securitization to finance the recovery of operations and maintenance (O&M) expenses related to catastrophic wildfires pursuant to Assembly Bill (AB) 1054.[4] More specifically, PG&E seeks to finance up to the total authorized $2.356 billion of vegetation management (VM) O&M expenses for 2023 to 2024 (Authorized VM Expenses) through the issuance of Wildfire Rate Relief Bonds backed by a Wildfire Rate Relief Fixed Recovery Charge (WRRFRC).[5] It also seeks upfront financing costs associated with the issuance of Wildfire Rate Relief Bonds (Upfront Financing Costs), which are presently estimated to be approximately $15.4 million (collectively, the Authorized Amount).

PG&E has designed the proposed issuance to support affordability and equitable distribution of VM wildfire mitigation expenses over time. Table 1-1 summarizes the distinguishing features of the Wildfire Rate Relief Bonds. In particular, this application seeks to finance O&M expenses for a limited bond tenor of 10 years; targets only VM expenses; and addresses current affordability concerns by generating an immediate average rate reduction of approximately 2.7 cents per kilowatt-hour (kWh), or a reduction of 7 percent compared to rates in effect at the time of this filing, for a 12 month period from April 2025 through March 2026. All else equal, PG&E's request in this application would reduce the average non-CARE residential electric monthly bill by approximately $15.75 per month beginning in April 2025 through March 2026, with bills rising by approximately only $2.40 per month for the remainder of the bond term.[6]

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4 *Cf.* Decision (D.) 21-06-030 (bonds issued November 2021 to finance approximately $850 million of fire risk mitigation capital expenditures under Section 8386.3(e) (Initial AB 1054 Securitization)); D.22-08-004 (bonds issued November 2022 to finance approximately $975 million of fire risk mitigation capital expenditures (Second AB 1054 Securitization)); D.24-02-011 (bonds to be issued to finance approximately $1.38 billion in fire risk mitigation capital expenditures (Third AB 1054 Securitization)).

5 The WRRFRC will be imposed as a subcomponent of the existing Wildfire Hardening Fixed Recovery Charge (WHFRC) rate component.

6 For further details of the rate credit, see Chapter 7, Rate Proposal (B. Kolnowski), and its attachments. The residential bill impact is based on a non-CARE customer using an average of 500 kWh per month.

TABLE 1-1
KEY FEATURES OF THE WILDFIRE RATE RELIEF BONDS

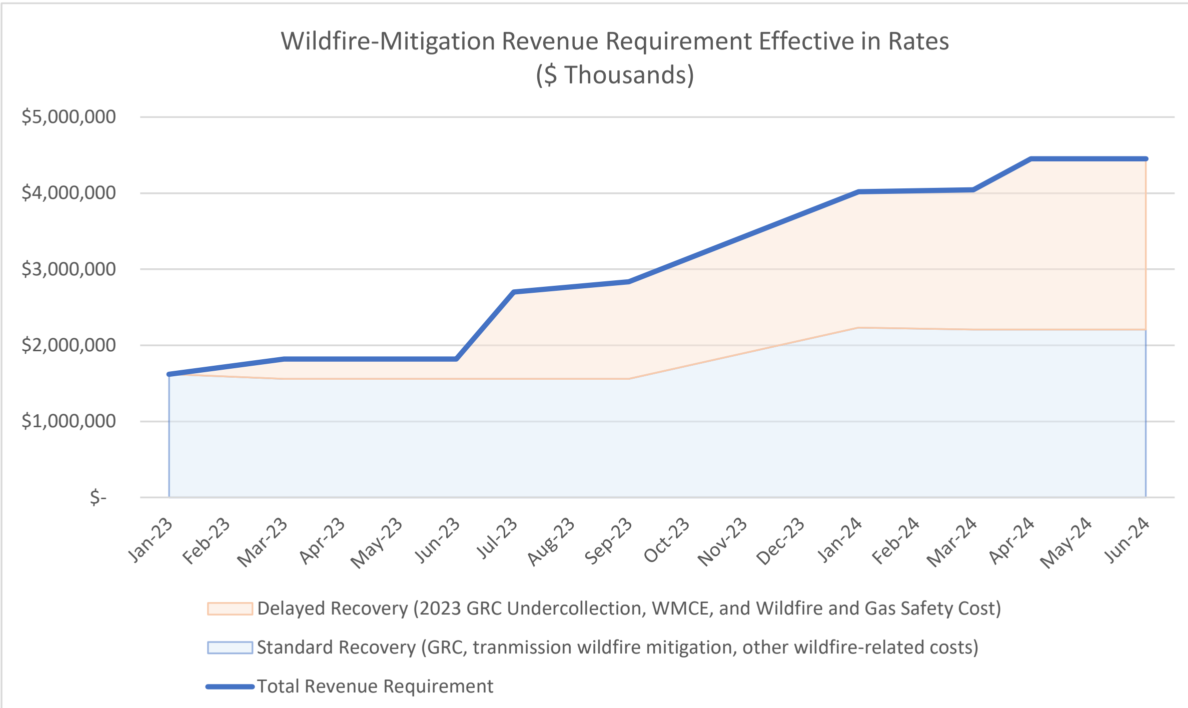
Line No.	Category	Key Features
1	Bond Tenor	10 years
2	Category of Wildfire Costs Financed	O&M Expenses (VM)
3	Rate Credit (Year 1)	$15.75 per month on average
4	Bill Increase (Years 2-10)	$2.40 per month on average
5	Net Present Value (approximate)	$122 million

This chapter presents: (1) the policy rationale for the Wildfire Rate Relief Bonds; (2) an overview of the Wildfire Rate Relief Bonds financing transaction; and (3) an overview of the chapters of testimony in support of the application.

B. Rationale for the Wildfire Rate Relief Bonds

The Wildfire Rate Relief Bonds will provide substantial and immediate bill relief to PG&E customers. Pursuant to its Wildfire Mitigation Plan (WMP), as reviewed and approved by the California Office of Energy Infrastructure Safety (OEIS), PG&E has continued to reduce wildfire risk through its wildfire mitigation initiatives and to further develop those programs to enhance their impact and cost-effectiveness. Such efforts include system hardening, the Enhanced Powerline Safety Settings (EPSS) program, and VM, among others. These costs are necessary, but significant, investments. The current combination of both increased capital costs and increased O&M expenses for these efforts due to the changing wildfire risk landscape in California, heightened contractor costs from Senate Bill (SB) 247, delayed recovery of costs including the delayed timing of the 2023 GRC decision and still pending Wildfire Mitigation and Catastrophic Events (WMCE) proceedings, has placed upward pressure on near-term customer rates and disproportionately impacted current customers. Figure 1-1 demonstrates this growth in overall wildfire mitigation costs effective in rates over time.

FIGURE 1-1
GROWTH IN WILDFIRE MITIGATION REVENUE REQUIREMENT IN RATES



These wildfire mitigation efforts, however, include significant costs that will benefit customers for years to come. The proposed Wildfire Rate Relief Bonds will provide an immediate rate credit to current customers and spread some of the costs for these efforts more equitably among current and future customers.

PG&E's VM program has experienced particularly significant cost growth, as shown by Table 1-2. While such costs are necessary for complying with General Order (GO) 95 and Public Resources Code (PRC) Sections 4292 and 4293, among other requirements, and VM is a required component of the WMP under Pub. Util. Code Section 8386,[7] the cost growth has resulted in rising customer rates. As noted in PG&E's 2023 GRC Decision,[8] VM costs have risen significantly since 2017, driven by a combination of factors including a heightened focus on, and stricter standards for, VM,[9] and increased contractor

7 Pub. Util. Code § 8386(c)(9) ("The wildfire mitigation plan shall include…[p]lans for vegetation management.")

8 D.23-11-069 at 343.

9 See, e.g., D.17-12-024 (Decision Adopting Regulations to Enhance Fire Safety in the High Fire-Threat District); see also 2023 GRC, PG&E-04, Workpapers (WP) 9-3, 9-4.

costs starting in 2020 from SB 247, which established qualifications for line clearance tree trimmers and required compensation at a prevailing wage rate,[10] among other factors. As a result, costs have grown, from $397 million in 2017 to $1.158 billion in 2023, peaking at $1.629 billion in 2022.

TABLE 1-2
GROWTH IN VEGETATION MANAGEMENT COSTS
(THOUSANDS OF DOLLARS)

Line No.	2016	2017	2018	2019	2020	2021	2022	2023
1	$382,444	$396,621	$638,682	$918,836	$1,249,500	$1,538,100	$1,629,200	$1,158,500

Note: Source: *Errata 2 2023 GRC Workpapers Ch 9 VM, SB-884 10 Year UG Plan, SPD_002 Data Request*.

PG&E is committed to continuing its ongoing efforts to reduce costs by streamlining the scope of the VM program, driving operational efficiency, and eliminating waste, and leveraging new technologies. Moreover, PG&E is committed to working with policymakers and stakeholders to identify additional ways to decrease or avoid increases in VM expenses that do not reduce PG&E's overall wildfire risk reduction, including updates to VM practices. PG&E believes that with such engagement, a lower cost structure is attainable. Nevertheless, current customers have borne a substantial share of those ongoing costs necessary to date, as well as higher capital costs for wildfire system hardening, all of which benefit customers for years to come. Thus, current customers are disproportionately impacted by the increased upfront costs of wildfire mitigation in their rates that benefit future customers as well.

The Wildfire Rate Relief Bonds will enable PG&E to “smooth out” the cost curve, i.e., spread out the rate impact over a longer period of time such that the

10 SB 247 required that “[a]ll electrical line clearance tree trimmers performing work to comply with the vegetation management requirements in an electrical corporation's wildfire mitigation plan shall be qualified line clearance tree trimmers, or trainees under the direct supervision and instruction of qualified line clearance tree trimmers” and that “[a]ll qualified line clearance tree trimmers shall be paid no less than the prevailing wage rate for a first period apprentice electrical utility lineman as determined by the Director of Industrial Relations.” Cal. Pub. Util. Code § 8386.6. For example, based on 2021 data from PG&E’s 2022 WMCE application, the impact of SB 247 incurred an additional 59 percent of the imputed adopted amount, or approximately an additional $355 million for routine and EVM programs, that was not forecast in the 2020 GRC. That constituted approximately 24 percent of the total recorded expenses in 2021.

cost incidence on customers more closely aligns with the associated real-world mitigation and cost reduction benefits. Specifically, the Wildfire Rate Relief Bonds will provide affordability benefits at a time when rates are rising and will spread those costs out over the subsequent 10-year period of repayment of the proposed Wildfire Rate Relief Bonds. The proposed rate credit and broader rate relief goals of PG&E's proposal make it somewhat distinct from prior bond transactions under AB 1054 focused on financing capital expenditures. Yet this approach is akin to prior rate reduction bond transactions in California that were used to reduce customer rates and finance costs for recovery over the term of the bonds.[11] And securitized bonds have been used elsewhere to recover costs associated with tree trimming activities.[12] As demonstrated in Chapter 7, Rate Proposal (B. Kolnowski), the proposed transaction delivers an immediate rate credit for customers from April 2025 through March 2026. Based on PG&E's proposal, a typical non-CARE residential customer would experience $15.75 in average monthly bill reductions from April 2025 through March 2026 (or $190 for the year), which would be approximately 7 percent off the average bill. Bills would increase by only $2.40 per month, on average, for the remainder of the 10-year period. The relatively short tenor of the bonds is intended to reflect the nature of the underlying wildfire expenses and when their benefits are provided to customers. In PG&E's view, this proposed Wildfire Rate Relief Bond issuance is the best way to significantly reduce customer bills in 2025 without compromising safety or other state policy goals.

In this way, the Wildfire Rate Relief Bonds comply with the requirements of Section 850 and promote the public interest. The Commission has previously determined that wildfire mitigation expenses—like PG&E's VM O&M here—are properly subject to securitization under Section 850(a)(2).[13] In that decision, however, the Commission denied a proposal by Southern California Edison Company (SCE) to securitize wildfire-related O&M and Uncollectibles arising

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11 See D.96-12-077, 70 CPUC 2d 207, 1996 WL 752460 (Dec. 20, 1996) (discussing AB 1890 and rate reduction bonds); *see also* California Pub. Util. Code §§ 840-847.

12 See, e.g., In the Matter of the Application of Dte Elec. Co. for A Fin. Ord. Approving the Securitization of Qualified Costs., No. U-21015, 2021 WL 2660677 (Mich. P.S.C. June 23, 2021).

13 D.21-10-025 at 15 ("As a threshold matter, we disagree with Intervenors' contention that § 850(a)(2) prohibits the Commission from considering wildfire mitigation expenses.").

from the COVID-19 pandemic using recovery bonds with a longer 25-year scheduled tenor. In particular, under the "specific facts" in that proceeding, the Commission could not "conclude that SCE's proposed securitization [wa]s in the public interest pursuant to § 850.1(a)(1)(A)(ii)(II)" and that it would "provide both short--term and long--term economic benefits to ratepayers."[14] In particular, the Commission found that benefits of securitization "over a 25--year bond term" were outweighed by "associated financing costs and higher utility rates for future customers."[15]

PG&E has specifically designed its proposed Wildfire Rate Relief Bonds to address the Commission's concerns with that proposal. PG&E's proposed cash-neutral transaction provides both short-term and long-term benefits to customers. In the short term, as described further in Chapter 7, the proposed issuance is forecasted to yield an immediate residential average bill reduction of $15.75 per month at a time when customer rates and bills have increased due to previously incurred and ongoing wildfire mitigation costs, among other factors. Furthermore, over the longer term, the proposed issuance aligns more equitably with the real-world mitigation and cost -reduction benefits of VM. Indeed, PG&E is proposing a shorter tenor for the recovery bonds of 10 years, as compared to the 25-year tenor at issue in D.21-10-025, to reflect this alignment. This ensures that future generations paying the bond costs benefit from the underlying costs being financed.

As noted in Chapter 4, Customer Benefits (D. Raman, K. Rasheed), the VM program produces benefits ranging from shorter-term benefits of at least a year to longer-term benefits of permanent or extended duration. For example, pruning/trimming provide benefits lasting at least one year and often multiple years, depending on various factors. When pruning/trimming are unlikely to yield multi-year benefits and would necessitate repeated efforts on an annual or biannual basis, removal is the preferred option, which yields permanent or extended mitigation benefits. As a result, the proposed Wildfire Rate Relief Bonds are designed to address the disproportionate cost impact of long-term

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14 *Id*. at 27.

15 *Id.* at 27-28.

benefits in the current rate trajectory and more fairly allocate those costs between current and future customers.

C. Overview of the Wildfire Rate Relief Bonds Transaction

The proposed Wildfire Rate Relief Bonds transaction is pursuant to and satisfies AB 1054 and Sections 850(a)(2) and 850.1, which permit financing of "costs and expenses related to catastrophic wildfires" that the Commission finds to be just and reasonable.[16] The application seeks to finance up to the Authorized VM Expenses of $2.356 billion of VM expenses actually incurred in 2023 and 2024, including both expenses incurred as of the date of this application and expenses incurred thereafter in 2024. The Commission deemed these expenses related to VM to be just and reasonable in D.23-11-069, the final decision in PG&E's 2023 GRC.[17]

The proposed bonds also satisfy the other requirements of Section 850.1(a)(1)(A). This issuance of Wildfire Rate Relief Bonds would benefit customers by providing low cost financing for VM expenses. As explained more fully in Chapter 2, Background on Utility Securitization (K. Niehaus), Chapter 3, Transaction Overview (M. Klemann), and Chapter 4, Customer Benefits (D. Raman, K. Rasheed), the structural features of securitization to recover these expenses ensures financing at a lower cost than the use of traditional utility financing mechanisms, as defined by AB 1054. Further, the proposal promotes the public interest by providing immediate rate relief to customers and more equitably distributing costs among customers.

Although the proposed transaction differs from PG&E's prior AB 1054 Capex transactions with respect to the type of costs proposed to be financed, it otherwise closely tracks the framework for PG&E's prior AB 1054 transactions. To facilitate review by the Commission and other parties, the application attaches a redlined version of the Form of Financing Order against the financing

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16 Pub. Util. Code §§ 850(a)(2), 850.1.

17 D.23-11-069 at 334-344.

order for the Third AB 1054 Securitization that reflects the proposed changes to D.24-02-011 to implement the Wildfire Rate Relief Bonds.[18]

1. The Expenses to Be Financed

Through the Wildfire Rate Relief Bonds, PG&E would finance and recover a portion of its VM expenses, which consists of VM O&M expenses associated with PG&E's Community Wildfire Safety Program (CWSP) and its WMP incurred on or after January 1, 2023, with the total amount of VM expenses subject to Wildfire Rate Relief Bonds not to exceed the Authorized VM Expenses.

As explained in PG&E's 2023 GRC Application (A.) 21-06-021, the purpose of the CWSP is to reduce the risk of catastrophic wildfires from electric utility infrastructure in PG&E's service territory through a number of programs and activities that have been presented and explained in PG&E's WMP.[19] The WMP is subject to review and approval by OEIS and comprehensively addresses PG&E's activities to reduce wildfire risk. PG&E's WMP and CWSP continue to improve and evolve in response to new information, lessons learned, and evolving conditions and policies, including those of the Commission.[20]

One essential wildfire risk reduction activity required under PG&E's WMP is VM. Under PG&E's VM program, PG&E annually inspects approximately 100,000 miles of powerlines, trims, or removes more than 1 million trees, and addresses dead or dying trees.[21] These programs

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18 To avoid any adverse timing effect on PG&E's contributions to the Customer Credit Trust (CCT) from the proposed financing, PG&E will ignore the impact of the Wildfire Rate Relief Bonds for purposes of determining its contributions to the CCT. Specifically, in connection with the methodology for calculating PG&E's Additional Shareholder Contributions to the CCT approved in D.21-04-030, PG&E will determine its taxable income without regard to the impacts of the rate credit PG&E is providing to customers as part of the Wildfire Rate Relief Bond issuance and imposition of the WRRFRC.

19 PG&E's most recent updated WMP, filed March 27, 2023 and last revised on April 2, 2024 is available at: https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/wildfire-mitigation-plan.page?WT.mc_id=Vanity_wildfiremitigationplan (as of June 3, 2024).

20 A.21-06-021 (2023 GRC), PG&E-4 (Feb. 25, 2022), Chapter 4, at 4-1.

21 WMP Rev. 5 (April 2, 2024) at 602.

support PG&E's compliance with GO 95 and PRC Section 4292 and 4293, which require, *inter alia*, clearance areas surrounding power lines.

As described in PG&E's 2023 GRC application, VM is primarily composed of three programs: Routine Vegetation Management, Enhanced Vegetation Management (EVM), and Tree Mortality. The Routine VM program patrols and completes identified tree work on overhead distribution facilities to maintain clearance between vegetation and conductors. It also identifies trees that will encroach within minimum distance requirements and hazard trees that have the potential to strike conductors. The EVM program includes three programs: Focused Tree Inspections (FTI), VM for Operational Mitigations (VMOM), and Tree Removal Inventory (TRI). Finally, the Tree Mortality program engages in removal of dead or dying trees, the presence of which would otherwise worsen wildfire risk. PG&E is continuing to streamline its high priority VM programs into its "One VM" platform, which will allow for more efficient tracking and management, optimization of work activities, improved situational awareness, and bundling of VM activities. PG&E's VM program is directed and supported by wildfire risk modeling, which identifies where wildfire risk is highest and where mitigation efforts may be most effective.

The Wildfire Rate Relief Bonds include the following VM expenses described in PG&E's WMP:

- Expenses incurred in 2023-2024 (Wildfire VM Expenses) recorded to the one-way Vegetation Management Balancing Account (VMBA), only up to the amount of Authorized VM Expenses.[22] D.20-12-005 resolved PG&E's 2020 GRC proceeding, and the Commission there approved a settlement that allowed the VMBA to operate as a two-way balancing account tracking both Enhanced and Routine VM expenses, and also directed PG&E to track Tree Mortality work in the VMBA.[23] In the 2023 GRC decision, the Commission continued the VMBA but modified the

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22 The VMBA was initially authorized by the Commission in D.00-02-046, the decision resolving PG&E's 1999 GRC proceeding, and was authorized as a one-way balancing account.

23 D.20-12-005 at 78 ("With respect to the proposed two-way treatment of costs, we agree with this approach…"); D.20-12-005 at 67 ("[B]eginning in TY 2020, PG&E shall track all vegetation management costs in its VMBA.")

account to a one--way balancing account to record all VM expenses.[24] These 2023-2024 VM expenses were approved as just and reasonable in the 2023 GRC decision.

Table 1-3 shows the total amount of VM expenses that are expected to be recorded to the VMBA by the end of 2024. As shown by Table 1-2, the Wildfire VM Expenses up to the Authorized VM Expenses will be approximately 50 percent of the total amount of VM expenses authorized by the Commission in the 2023 GRC Decision for the rate case period.

TABLE 1-3
2023 GRC VEGETATION MANAGEMENT BALANCING ACCOUNT SPEND
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description of Vegetation Management	Total
1	2023 GRC – 2023 VMBA	
2	January 2023 through December 2023 (recorded)	$1,158,542
3	2023 GRC – 2024 VMBA	
4	January 2024 through March 2024 (recorded)	287,892
5	March 2024 through December 2024 (remaining adopted/imputed)	909,656
6	Total	$2,356,090

Consistent with prior bonds,[25] PG&E will set forth in an Issuance Advice Letter the total amount of Wildfire VM Expenses actually financed using securitization (up to the Authorized VM Expenses), which will be based on recorded expenses in the VMBA from January 2023 through December 2024. The ratemaking treatment for the Wildfire VM Expenses to be financed pursuant to this application, and the rate credit associated with issuance of the Wildfire Rate Relief Bonds, are discussed briefly below and in more detail in Chapter 6, Ratemaking Mechanisms (S. Sims).

2023 GRC Adopted VM Expenses – Table 1-4 below shows the total VM expenses adopted by the Commission in the 2023 GRC Decision and found to be just and reasonable for the 2023 through 2026 rate case period. As previously noted, the Commission continued the VMBA, with

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24 D.23-11-069 at 486-487.

25 See D.21-06-030, Attachment 2 at 2-2; D.22-08-004, Attachment 2 at 2-2 to 2-3; D.24-02-011, Attachment 2 at 2-2.

modifications to a one-way balancing account, to record these expenses. As set forth in the preliminary statement for the VMBA, the purpose of the VMBA is to record actual expenses related to Routine VM, EVM, Tree Mortality and Fire Risk Reduction work up to adopted amounts for the entire GRC funding cycle.[26]

TABLE 1-4
TOTAL VM EXPENSES IMPUTED ADOPTED COSTS IN 2023 GRC DECISION
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program	2023	2024	2025	2026	Total
1	Routine Vegetation Management	$972,013	$965,868	$963,767	$968,867	$3,870,515
2	Enhanced Vegetation Management (FTI, VMOM and TRI)	131,816	130,933	130,601	131,254	524,604
3	Tree Mortality	77,991	77,469	77,273	77,659	310,392
4	Total	$1,181,820	$1,174,270	$1,171,641	$1,177,780	$4,705,511

PG&E will include Wildfire VM Expenses up to the Authorized VM Expenses for 2023 and 2024, which is $1,181,820,000 in 2023 and $1,174,270,000 in 2024, for a total of $2,356,090,000 over both years.

2024 GRC VM Expenses – Consistent with the work plan set forth in PG&E's 2023 GRC testimony and WMP, PG&E anticipates that VM expenses will continue to be recorded to the VMBA following the date of filing this application through December 2024 and seeks authorization to include those actual amounts incurred through the end of 2024, with the total to not exceed the Authorized VM Expenses.

2. Total Authorized Amount of Wildfire Rate Relief Bonds

In addition to the Wildfire VM Expenses, the principal amount of the issuance of Wildfire Rate Relief Bonds would include Upfront Financing Costs.

The Upfront Financing Costs reflect the costs of this application and issuing the Wildfire Rate Relief Bonds. The Upfront Financing Costs are estimated to be $15.4 million,[27] and are discussed in Chapter 3,

[26] Electric Preliminary Statement Part BU Sheet 1.

[27] The amount of Upfront Financing Costs is estimated in Table 1-5. The actual amount will be calculated at the time of issuance and included in the Issuance Advice Letter.

Transaction Overview (M. Klemann). Table 1-5 sets forth the Authorized Amount requested for the Wildfire Rate Relief Bonds.

TABLE 1-5
TOTAL ESTIMATED AUTHORIZED AMOUNT
(THOUSANDS OF NOMINAL DOLLARS ROUNDED)

Line No.	Description	Amount
1	Authorized VM Expenses	$2,356,090
2	Upfront Financing Costs (estimated)	15,404
3	Total Estimated Authorized Amount	$2,371,494

3. Revenue Allocation and Revenue Requirement Adjustments

With respect to rate design and allocation among customers, consistent with the revenue allocation settlement agreement adopted by the Commission in the 2020 GRC Phase II proceeding (RA Settlement Agreement),[28] D.21-06-030,[29] D.22-08-004,[30] D.24-02-011,[31] the WRRFRCs would be imposed as a subcomponent of the existing WHFRC rate component on all non-exempted customers based on the allocation methodology set forth in the RA Settlement Agreement. The rate design and allocation is described in detail in Chapter 7, Rate Proposal (B. Kolnowski).

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[28] See D.21-11-016 at 87-90 (Section 6.6.4, "Allocation of Wildfire Mitigation Costs," describing methodology and explaining that "To the extent PG&E files a subsequent application for securitized AB 1054 costs, before its next GRC Phase 2 proceeding, PG&E would propose to use the wildfire mitigation cost allocation approach of the RA settlement to determine the allocation factors to be applied at the time of issuance of those subsequent bonds as well, after any potential securitization is approved."). See also *id.* at 168 (OP 15) ("Pacific Gas and Electric Company shall implement the provisions of the revenue allocation settlement as soon as practicable.").

[29] D.21-06-030 at 81 ("We agree that the terms of the Settlement Agreement apply to these wildfire mitigation securitization Recovery Bonds. Therefore, the methodology set forth in the Settlement Agreement binds the parties to this proceeding. Moreover, we find the revenue allocation methodology set forth in the Settlement Agreement is reasonable and applicable for the Recovery Bonds at issue here.").

[30] D.22-08-004 at 77-78.

[31] D.24-02-011 at 78-80.

Consistent with D.21-06-030, D.22-08-004, and D.24-02-011,[32] upon the issuance of the Wildfire Rate Relief Bonds authorized pursuant to this application, PG&E will record a credit entry to the Distribution Revenue Adjustment Mechanism (DRAM) equal to its actual incurred VM expenses financed using Wildfire Rate Relief Bonds to provide a rate credit to customers. These adjustments are described in Chapter 6, Ratemaking Mechanisms (S. Sims). PG&E requests authority to make those adjustments through the next rate change advice letter following issuance of the Wildfire Rate Relief Bonds.

4. Capital Structure

Consistent with the Initial AB 1054 Securitization, Second AB 1054 Securitization, Third AB 1054 Securitization, and other Commission financing orders authorizing the issuance of recovery bonds pursuant to Sections 850 *et seq.*, PG&E proposes to remove from PG&E's ratemaking capital structure the securitized debt issued in connection with the Wildfire Rate Relief Bonds.[33]

D. Overview of PG&E Testimony

PG&E's testimony in support of this application comprises seven chapters, summarized as follows:

- <u>Chapter 1, Introduction (M. Becker):</u>

  Chapter 1 presents an introduction to the Wildfire Rate Relief Bonds, including the legal and factual background and an overview of the transaction. The proposed Form of Financing Order is Attachment A to the application, and Attachment B is a redlined version of the Form of Financing Order that reflects the proposed changes to D.24-02-011 to implement the Wildfire Rate Relief Bonds.

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32 D.21-06-030 at 2, 128 (OP 46); D.22-08-004 at 123 (OP 46); D.24-02-011 at 126 (OP 46).

33 See D.21-06-030 at 128 (OP 44). *See also* D.21-10-025 at 108 (OP 44); D.21-04-030 at 93 (OP 18); D.20-11-007 at 126 (OP 51).

- Chapter 2, Background on Utility Securitization (K. Niehaus):

  The proposed Wildfire Rate Relief Bonds are part of a category of financial instruments generally described as asset backed securities (ABS). This chapter is sponsored by Katrina Niehaus, Managing Director, Investment Banking Division, at Goldman, Sachs & Co. (Goldman), PG&E's structuring advisor for the Wildfire Rate Relief Bonds. Chapter 2 provides general background on ABS, as well as a more detailed review of the market for utility securitizations. After providing an overview of the history of this market, it surveys the basic structuring principles of securitization financing, with a focus on the considerations relevant to utility securitizations. Chapter 2 also discusses the size of the market and the pricing mechanics, marketing strategies, and typical fees and expenses associated with these transactions. Finally, Chapter 2 discusses the anticipated treatment of the bonds by rating agencies, including the importance and adequacy of the proposed financing order to achieving the highest possible ratings as well as rating agencies' treatment of bonds in rating the utility's corporate credit.

- Chapter 3, Transaction Overview (M. Klemann):

  Chapter 3 provides an overview of the proposed Wildfire Rate Relief Bonds and explains the key considerations that determine the proposed structure of this transaction. These considerations include the need to structure the transaction to obtain the highest possible rating from credit agencies, as well as tax and accounting issues. In addition, Chapter 3 describes the characteristics, servicing, transaction costs, and use of net proceeds of the Wildfire Rate Relief Bonds. It also lays out details about the proposed collection and remittance of the fixed recovery charges.

- Chapter 4, Customer Benefits (D. Raman, K. Rasheed):

  Chapter 4 establishes that the Wildfire Rate Relief Bonds satisfy the requirements for issuance of recovery bonds set forth in Section 850.1(a)(1)(A)(ii)(III). That section states that, upon receiving an application for a financing order, the Commission shall issue the financing order if it finds, among other things, that the issuance of the bonds, including all material terms and conditions and the imposition and collection of the WRRFRCs would reduce, to the maximum extent possible, the rates on a present value basis that customers would pay as compared to use of traditional utility financing.[34]

Chapter 4 establishes that the Wildfire Rate Relief Bonds will reduce customer rates on a present value basis to the maximum extent possible as compared to traditional utility financing. First, as required by statute, Chapter 4 compares the revenues that PG&E would need to collect from customers to recover the Authorized VM Expenses using traditional ratemaking at PG&E's authorized rate of return on rate base (7.8 percent),[35] as opposed to financing through securitized debt. Second, Chapter 4 describes how the proposed bonds have an estimated positive net present value of approximately $122 million for customers, relative to a scenario in which no such transaction occurs.

Finally, Chapter 4 details the extended benefits from VM, demonstrating that the proposed bonds equitably align the rate impact on customers from securitization with the long-term benefits from ongoing VM expenses.

- Chapter 5, Taxation (T. Wedlake):

  Chapter 5 describes the tax implications of the Wildfire Rate Relief Bonds.[36] Specifically, securitization-related customer charges are recognized as income to the utility as they are collected over time. While PG&E anticipates that the federal income and State of California franchise taxes associated with such charges from customers will be offset by tax benefits associated with the securitization, timing differences will require the use of a fixed recovery tax amount (FRTA) as provided in Section 850(b)(8). Chapter 5 describes the normalized ratemaking treatment associated with the WRRFRCs. As discussed in Chapters 6 and 7, PG&E proposes to track the amount of the FRTA in the WHFRCBA outside of the securitization using standard ratemaking mechanisms, and hence will not include these amounts in the WRRFRC.

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[34] Pub. Util. Code § 850.1(a)(1)(A)(ii)(III).

[35] D.22-12-031, as corrected by D.23-01-002.

[36] The treatment of taxes is based on the facts and circumstances specific to the Wildfire Rate Relief Bonds. PG&E may change the proposed treatment in a subsequent application for a financing order under Sections 850, *et seq*.

- Chapter 6, Ratemaking Mechanisms (S. Sims):

  Chapter 6 describes PG&E's ratemaking mechanisms for the Wildfire Rate Relief Bonds. Specifically, Chapter 6 describes the balancing accounts necessary to ensure repayment of the Wildfire Rate Relief Bonds and accurate accounting for associated transactions, including the cost or benefit of franchise fees, FRTA amounts, and the incremental costs of servicing and administration related to the issuance and payment of the Wildfire Rate Relief Bonds. This chapter also describes the adjustments to PG&E's 2023 GRC revenue requirements recorded in the DRAM that will be implemented in connection with the Wildfire Rate Relief Bonds.

- Chapter 7, Rate Proposal (B. Kolnowski):

  Chapter 7 describes PG&E's proposed rate design, cost allocation among customers for the WRRFRCs and the FRTA amounts, and illustrative rates for the WRRFRCs that will be sold and pledged to secure the Wildfire Rate Relief Bonds. Chapter 7 also describes how PG&E proposes to present the WRRFRCs on customer bills. Finally, Chapter 7 describes the proposed credit and its bill impacts for customers.

- Appendix A – Qualifications of Witnesses:

  This appendix sets forth the qualifications of each of the witnesses sponsoring the testimony in support of the application.

E. Conclusion

PG&E respectfully requests that the Commission approve the proposed transaction and transaction structure for the Wildfire Rate Relief Bonds as described in the application and supporting testimony.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

BACKGROUND ON UTILITY SECURITIZATION

WITNESS: KATRINA T. NIEHAUS

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A. Introduction

This chapter provides a general overview of Asset-Backed Securities (ABS) as well as a more detailed review of the market for "utility securitizations."[1]

A brief overview of the history of both the ABS market and utility securitization market will be provided. Additionally, the basic structuring principles of securitization financings will be reviewed with a specific focus on utility securitizations. Finally, this chapter will also discuss the size of the ABS market as well as the pricing mechanics, marketing strategies, and typical fees and expenses for these transactions.

B. Overview of the Securitization Market

1. History of the Securitization Market

The ABS market developed as an outgrowth of the mortgage-backed securities market in the 1980s. Pools of mortgage loans were packaged into highly rated, liquid, and marketable securities that were primarily sold to institutional investors. Cash flows from the underlying pool of mortgage loans were used to pay interest and principal on the offered securities.

The ABS market expanded the use of this technique to include a variety of financial assets that have predictable cash flow streams. Some of the most common asset classes financed through securitization include auto loans/leases, credit cards, and equipment leases, as well as a variety of unsecured consumer obligations. Historically, many utilities have raised securitization financing in the bank market backed by their account receivables from ratepayers. Over the years, the securitization market has grown significantly, and total term debt issuance in the public markets in 2023 across all ABS asset classes was approximately $262.8 billion and around $146 billion

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[1] The term "utility securitizations" is intended to cover securitization financings backed by a non-bypassable charge that allows regulated electric utilities to recover a variety of costs, such as "stranded costs," storm recovery costs, pollution costs, nuclear or environmental remediation costs, wildfire recovery and rate stabilization costs.

in 2024 year-to-date (YTD) issuance.[2] Additionally, there is significant securitization funding provided by a number of banks, insurance companies and other institutional investors outside the public markets.[3]

In the mid-1990s, another asset class—generally referred to in this chapter as "utility securitization"—was introduced to the securitization market. In 1995, Puget Sound, the first issuer of utility securitization bonds, issued approximately $202 million of conservation bonds backed by an intangible property right to bill and collect securitization charges from the utility's customers related to prior investments in energy efficient-equipment for its customers.

Not long after the Puget Sound issuance, the State of California signed into law comprehensive legislation (Assembly Bill (AB) 1890) that restructured the state's electric utility industry by opening up the market for electricity generation to competition and, thereby, encouraging lower rates for electricity. A critical feature of this initiative was the commitment of the California Public Utilities Commission (CPUC or Commission) to provide investor-owned electric utilities an opportunity to recover up to 100 percent of their "stranded costs."[4] Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company and Sierra Pacific Power Company all took advantage of this opportunity by arranging for the issuance of securitization bonds. The recovery of these "stranded costs" took place by the issuance of over $6 billion of "rate reduction bonds," in order to provide residential and commercial customers rate relief, and the primary collateral for which was the utility's statutory right to bill and collect a "fixed transition amount" on the electric bill of residential and small commercial customers.

A second set of utility securitizations took place in the State of California in connection with the California energy crisis. In 2005, PG&E issued in aggregate

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2 Please refer to Table 2-2 for further details.

3 These financings are private in nature and no market data is therefore available.

4 Stranded costs are, broadly speaking, costs that are rendered uneconomic as a result of the emergence of a deregulated or competitive market for the generation of electricity. Typical examples include unrecovered investments in above-market generation (particularly nuclear plants), commitments to above-market power purchase contracts and so-called "regulatory assets" that represent a regulatory promise to collect future revenues related to past investments and, more recently, carbon-fired generation plants closed in advance of their expected useful lives.

approximately $2.7 billion of energy recovery bonds through two separate transactions.

Since 2005, the utility securitization market has continued to expand. To date, over $60 billion of utility securitization transactions have been completed. In addition, the purposes of utility securitizations have evolved over time, to include (in addition to the recovery of "stranded costs") the recovery of storm costs, pollution control equipment costs, plant closure costs and rate stabilization costs. While the costs to be recovered may be different, the underlying principle of utility securitization is to recover those costs at a lower rate than could be achieved using traditional methods.

A third wave of utility securitizations in California was initiated after the legislature authorized securitizations to recover the costs of catastrophic wildfires, including mitigation expenses (AB 1054) and catastrophic wildfire costs and expense Senate Bill (SB 901). SCE closed the first transaction authorized by the Commission under AB 1054 on February 24, 2021. PG&E issued its first AB 1054 related transaction on November 12, 2021, followed by SCE's second AB 1054 transaction on February 15, 2022, PG&E's second AB 1054 transaction on November 30, 2022 and SCE's third AB 1054 transaction on April 27, 2023. PG&E anticipates pricing its third AB 1054 transaction in the summer of 2024. In between the AB 1054 transactions, PG&E issued two securitizations under SB 901 (another piece of legislation authorizing the financing of storm costs). In total, there have been approximately $3.5 billion in California securitization transactions under AB 1054 (not including the PG&E transaction expected to price in the summer of 2024) and $7.5 billion under SB 901.

2. Basic Structuring Principles in Standard Securitizations

<u>Bankruptcy and Legal Considerations:</u>

Securitizations, like all structured financings, are designed to take into account a wide range of financial, rating agency, legal, tax and accounting objectives.

Typically, the single most important structural driver for a securitization transaction is the objective of ensuring that the credit quality of the securities is delinked from (and may be higher than) that of the originating company such that highly rated (typically (AAA)(sf)) bonds can be sold to investors at attractive interest rates. This is true for all securitization issuances, regardless of the credit worthiness (including bankruptcy status) of the originating company. Without this delinking through a legal separation of the bond issuer from the originating company, the maximum allowable ratings uplift of the securitization transaction above the unsecured credit rating of the originating company would in most cases not result in the desired AAA(sf) rating.

The process for achieving this legal separation of the securitized assets entails an absolute transfer (contribution or sale) of the assets to a bankruptcy-remote Special Purpose Entity (SPE). The transfer of the assets is structured as a “true sale” for legal purposes. In addition, the organizational documents of the SPE, in order to establish “bankruptcy-remoteness” from the originating company: (a) require one or more independent members on its board of directors, in the case of a corporation or a limited liability company, or an independent trustee, in the case of a trust; (b) impose restrictions on the SPE’s ability to declare bankruptcy voluntarily or to engage in corporate reorganizations; and (c) substantially limit the activities of the SPE to those related to the securitization.

The rating agencies generally require “true sale” and “non-consolidation” opinions from legal counsel providing assurance that the assets have been transferred for bankruptcy purposes to the SPE and that the assets would not be part of the bankruptcy estate of the originating company and thus would not be available to creditors of the originating company in the event of an originator bankruptcy.

Securitizations are structured so that the SPE also has a security interest in the securitized assets transferred to the SPE, which is generally perfected through filing a financing statement under the Uniform Commercial Code (UCC Financing Statement). The UCC Financing Statement memorializes the SPE’s security interest by documenting that the securitized assets, as of a specified cutoff date, and all collections related to those assets are owned by the SPE. The UCC Financing Statement protects the SPE’s security interest in the securitized assets and limits another party’s ability to claim ownership over those assets, thereby protecting the rights of the secured investors in the SPE. Some state utility securitization statutes (including the California statutes) also provide for a “statutory lien” upon the securitized assets transferred to the SPE.

Servicing Considerations:

Following the closing of a securitization, the originating entity of the securitized assets will typically have responsibility for “servicing” the collateral pool. The servicer typically receives compensation for servicing the securitized assets, consistent with the costs of servicing similar assets.

These servicing responsibilities are set forth in a servicing agreement and typically include obligor billing (preparation and distribution of billing statements), collecting payments from obligors, resolving billing disputes, and remitting collections to a trustee. Additionally, the servicer will generate periodic reports on the collateral pool (collateral performance and performance related trigger events), determine allocation of cash collections, and prepare distribution instructions, all in accordance with the transaction documentation. Typically, a securitization transaction involves a trustee (generally a specialized trust department of a large financial institution) that holds a security interest in the securitized assets pledged on behalf of the investors and is responsible for making debt service distributions to investors from transaction dedicated collection accounts.

The originating entity, as servicer for the securitization, is contractually obligated to act with the same level of care and to service the securitized assets in the same manner as if the assets had not been transferred. Because investors look to the securitized assets for repayment—and generally do not have recourse to the originating company if the cash flows from the securitized assets are insufficient for repayment—rating agency and investor due diligence focuses on the credit quality of the securitized assets as well as the quality and experience of the servicer.

In the event of a servicing default by the origination company, the transaction documents typically allow the trustee (as instructed by the bondholders) to appoint a replacement servicer.

Rating Agency Considerations:

The major rating agencies all have published asset class specific ratings criteria summarizing their analytical approach for evaluating legal requirements (see discussion above) as well as their basic credit analysis for the applicable asset class.

As noted above, from a credit perspective, the objective of a securitization is to achieve a credit rating for the transaction based primarily on the credit quality of the securitized assets, with little to no consideration of the credit quality of the originating entity. Rating agencies will evaluate several factors in assessing the credit quality of the assets securitized. For standard securitizations backed by pools of loans or receivables (e.g., auto loans, credit cards, or account receivables), the main credit factor related to the assets is the potential for cash flow impairment resulting from delinquencies (delay in obligor payments) or losses on the securitized assets (obligor defaults). Depending on the structure of the securitization, credit losses or cash flow disruptions due to delinquencies or losses may cause an inability to meet debt service payments on the securitized debt.

When analyzing the securitized assets, the rating agencies will also take into account the size and diversity of the obligor base, as well as any geographic or product-specific concentrations in the pool, in order to determine whether these factors could significantly impact the credit performance of the pool. The rating agency review process is typically based on a statistical analysis of a pool of diversified payment obligations. Accordingly, securitization pools that are not sufficiently diverse or that have one or more obligors representing a significant portion of the assets, may not be ideal for securitization.

The structure of the securitization transaction is also an important factor in the rating agency analysis. In a hypothetical example with no credit enhancement, the ratings of the securitization would be based exclusively on the credit quality and performance of the underlying securitized assets. As such, the securitization would be susceptible to investor losses to the extent there are losses on the underlying securitized assets, the structuring of a securitization typically includes various forms of credit enhancement that enable the transaction to be more resilient to losses and achieve a higher rating. This credit enhancement may consist of a combination of the following:

- Overcollateralization: the transfer of securitized assets to the SPE with an aggregate payment obligation in excess of the amount necessary to repay the securitized debt amount;
- Excess spread: interest earned on securitized assets that is in excess of the aggregate amount of interest on the notes, the servicing fee, and other administrative expenses;
- Subordinate classes with lower designated credit ratings (based on the priority of interest and principal payments);
- Cash reserve accounts;
- A surety bond or letter of credit provided by a highly rated financial institution; and/or
- Legal Final Maturity: Rating agencies rate bonds to a legal final maturity which allows for extension of the bond beyond the expected maturity in the case of lack of cashflows sufficient to repay the bonds.

The aggregate required credit enhancement for a particular class of notes is determined by applying increasingly stressful assumptions to the projected cash flow collections from securitized assets for each successively higher rating category. Many standard securitization transactions are structured with the senior most notes having AAA(sf) ratings to take advantage of the associated borrowing cost savings. (Note that certain asset classes may not qualify for AAA(sf) ratings.)

For utility securitizations, the rating agencies also consider the impact of the securitization on the customers, specifically how much the securitization charges will increase the typical residential customer's invoice. When performing this analysis, the rating agencies will generally consider all securitizations associated with the customer (not just the transaction being rated).

Finally, the servicer's servicing ability, credit quality (as defined by the rating agencies), and business experience will be reviewed by the rating agencies as part of their due diligence.

<u>Accounting Considerations:</u>

While the securitized assets are legally transferred to an SPE as described above, United States (U.S.) Generally Accepted Accounting Principles (GAAP) typically requires the originator (which is generally also the servicer) to consolidate the SPE. As a result, the assets and liabilities associated with the securitization are consolidated with the assets and liabilities of the originator for financial statement purposes.

Tax Considerations:

From a tax perspective, two basic issues are typically considered when structuring a securitization: (a) whether any income taxes are triggered in connection with the transfer of the securitized assets from the originator to the SPE; and (b) whether any income taxes are triggered at the SPE level from the ongoing activities of the SPE.

Securitizations are typically characterized as debt for tax purposes, in which case the assets are deemed to have been "pledged" to secure the originator's debt. "Debt for tax" characterization means that the assets are still deemed to be owned by the originator for tax purposes, which defers any potential immediate tax liability. Instead, taxes are payable over time as the revenues, in respect of the securitized asset, are billed. For tax purposes, the originator continues to be the owner of the securitized assets, reports income generated by the securitized assets and deducts interest expense payable by the SPE. In the context of utility securitizations, consistent with Revenue Procedure 2005-62 (as recently amended by Revenue Procedure 2024-15), which I will discuss later in my testimony, counsel typically requires that the SPE be capitalized by an equity contribution from the utility of not less than 0.50 percent of the original principal amount of the securitization to support debt treatment for tax purposes. To the extent State tax law mirrors Federal law or otherwise accommodated in the enabling legislation, treatment of any State income taxes is (customarily) addressed in the same manner.

As it relates to taxation of the ongoing activities of the SPE, securitizations are typically structured such that the SPE is disregarded for tax purposes (i.e., no taxes are paid at the entity level). This is done in order to avoid any reductions in cash collections available to the noteholders resulting from tax obligations, including the impact from any future changes in tax laws.

3. Basic Structuring Principles in Utility Securitizations

While utility securitizations to a large extent are based on the principles discussed above, there are certain noteworthy distinctions. The next section describes these distinctions as well as the application of the basic structuring principles to a utility securitization.

Basic Utility Securitization Structure:

A utility securitization is a financing backed by an intangible property right to bill and collect securitization charges from some or all of the utility's customers, issued by an SPE that has securities whose credit quality is de-linked from that of the utility in order to achieve higher credit ratings and lower financing costs. In order to accomplish this, the utility sells the revenue stream and other entitlements and property created by a financing order issued by a public utility commission to a bankruptcy-remote SPE in a transaction that, consistent with the regulatory statute in the applicable state, represents a "true sale" for bankruptcy purposes. This sale insulates the securitization property from the creditors of the utility and, thereby, from the credit risk of the utility. The SPE issues securitization bonds to finance the purchase of the securitization property. The securitization bonds are secured by the securitization property that includes, among other things, the right to bill and collect non-bypassable securitization charges from the utility's customers and the right to periodic adjustments to the securitization charges such that collections are sufficient to satisfy scheduled debt service obligations and other costs and expenses relating to the transaction on a timely basis. A trustee acts on behalf of bondholders, makes debt service payments to bondholders, and protects bondholders' rights in accordance with the terms of the financing documents. The utility will perform routine meter readings, billing, collection, and reporting duties as the servicer for the SPE pursuant to a servicing agreement between the utility, the SPE, and the trustee. In addition to the "ring-fencing" of the securitized asset, credit enhancements, such as a capital contribution to the SPE and the true-up mechanism described below, are necessary to reach the rating standard for this type of securitization, which is the highest possible rating[5] from each of two or more of the major rating agencies.

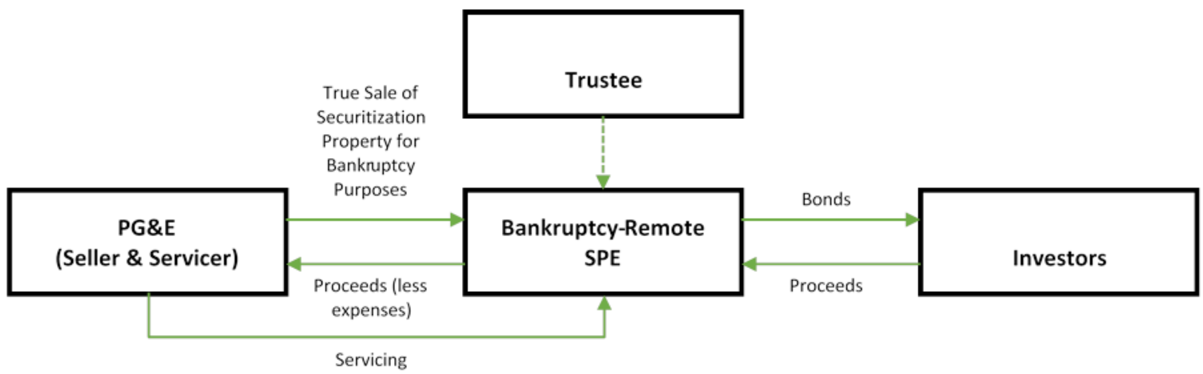
Unlike other securitizations, the primary source of credit enhancement in a utility securitization is a periodic adjustment known as the "true-up mechanism." The true-up mechanism is utilized to adjust the securitization charge, typically a volumetric (per kilowatt-hour (kWh)) charge, to correct for under-or over-collections primarily resulting from variances in the actual electric consumption, delinquencies of collections as well as write-offs in each case relative to the projections utilized to develop the securitization charges. The securitization charge is adjusted, generally on either a semiannual and/or an annual basis, as needed to ensure cash collections match the SPE's payment obligations. In early utility securitizations, the true-up mechanism provided for an annual true-up of the securitization charge. However, as sponsor utilities moved away from utilizing other forms of credit enhancement (including an overcollateralization account), the true-up mechanism has been enhanced to provide for more frequent true-ups. The current standard is for an annual review and true-up, and a mandatory semi-annual true-up if the servicer projects collections of the securitization charge will be insufficient to pay scheduled debt service. In addition, the servicer may request an additional true-up at any time if it projects that collections of the securitization charge will be insufficient to pay scheduled debt service and various transaction expenses. Although earlier utility securitizations included overcollateralization accounts, in recent times the credit enhancement for these transactions primarily comes from the true-up mechanism, so for most transactions an overcollateralization account is no longer necessary. An efficient and timely true-up mechanism provides significant credit support, allowing the rating agencies to rate the bonds at the targeted rating levels. The ability to make true-up adjustments expeditiously typically means that the commission's review of the true-up adjustment is limited to mathematical accuracy. Because the true-up mechanism is designed to prevent potential shortfalls in the timely payment

5 Utility securitizations typically receive AAA(sf) credit ratings from the major rating agencies. The 2015 and 2022 securitizations for Entergy New Orleans are an exception, as they are rated Aa1 by Moody's.

of scheduled debt service and transaction expenses, deficiencies in the collection of securitization charges from ratepayers (e.g., non-payments) may result in the reallocation of such deficiencies to other customers to the extent that a customer base exists to pay such additional securitization charges.

Figure 2-1 is representative of a utility securitization transaction:

FIGURE 2-1
UTILITY SECURITIZATION TRANSACTION STRUCTURE



The typical utility securitization financing structure and required cash flows reflect annual debt service and revenue requirements that are substantially level (except that the annual debt service and revenue requirements may be adjusted: (a) for the first period given an extended/shortened length; and (b) in general to reflect debt service requirements with respect to other utility securitizations previously issued).[6] Additionally, in geographical areas with significant seasonality in electric consumption, there may be further adjustments with respect to the periodic debt service and revenue requirements (semi-annual debt service payments are common). The projected levels for these requirements are designed to satisfy rating agency stress scenarios required for AAA(sf) ratings in precedent utility securitization bond transactions.

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6 For example, in 2009, securitized bonds were issued for The Potomac Edison Company and for Monongahela Power Company to finance cost overruns of a project previously financed by 2007 securitized bonds. Principal on those 2009 securitized bonds was scheduled to be paid only after all principal on the 2007 securitized bonds was scheduled to be fully repaid.

Utility securitizations have used a number of approaches to allocate the securitization charges associated with the debt service and related ongoing transaction costs among customers. Many recent transactions have allocated the securitization charges among customer classes based on a set of allocation percentages established for each customer class at the time of issuance of the financing order, permitting this allocation to be revised, if appropriate, provided that such revision does not impact the then-current rating on the bonds. Within each customer class the securitization charges allocated to specific customers are further determined by a combination of energy and/or demand consumption. There have, however, also been examples, such as the transaction for the State of Hawaii, where all customers paid an equal securitization charge per kWh. Such a rate structure can, in certain circumstances, be beneficial for the rating agency analysis as described above.

Unlike typical corporate bonds with date-certain maturities, the principal repayment requirements in utility securitization bonds reflect the uncertainty with respect to the ability to collect on a timely basis the required revenue amounts (which among other things may be influenced by differences between projected and actual electricity consumption).[7] In lieu of a single fixed maturity date for each bond, securitization bonds have scheduled amortization resulting in payment by an "expected" or "scheduled" final payment date (the date when principal is expected to be repaid) and then specify a "legal" maturity date (the date following the scheduled final payment date by which all principal is due). No legal obligation exists to retire a bond by the scheduled final payment date, only by the legal maturity date. Similarly, although the true-up mechanics are specifically designed to make scheduled principal payments on a timely basis, there are no legal obligations to satisfy scheduled amortization on scheduled principal payment dates. The legal maturity date of the securitization bonds generally may be up to two years beyond the scheduled final payment date. The ratings on the utility securitization bonds are derived in part based on the

7 Note that the true-up mechanism is a key structural element in managing such differences.

assumption that the outstanding principal of a class will be paid in full by the legal maturity date.

Most utility securitization bonds are issued with multiple tranches (i.e., individual sub-groups of bonds with different maturities and average lives) to take advantage of discrete pockets of investor demand across the entire term of the transaction. This is especially the case in transactions with extended tenors.

<u>Bankruptcy and Legal Considerations:</u>

Similar to conventional securitizations, one of the basic structuring objectives for a utility securitization is legal separation of the securitized asset from that of the utility's estate. This is achieved through the standard securitization structuring techniques involving a true sale and bankruptcy-remoteness of the SPE.

The nature of the assets being securitized is very different from other forms of securitizations. For most other securitization asset classes, the securitized asset is a diversified pool of obligations (e.g., auto loans or leases) with fixed payment amounts and due dates.

In a utility securitization, the transferred asset is composed of the rights and interests of the utility created pursuant to legislation and a financing order. This includes the right to impose, collect, and receive from the utility's electric customers amounts necessary to pay principal and interest on the securitization bonds, as well as the SPE's other ongoing costs and expenses (such as servicing fees, trustee fees and expenses, legal fees, auditor expenses, administration fees, rating agency fees, independent manager fees, Securities and Exchange Commission (SEC) reporting expenses, and other operating expenses incurred by or on behalf of the SPE), timely, in full, and including the ability to adjust the amounts of the securitization charges periodically through a "true-up" mechanism.

The securitization property, the SPE's rights under the transaction documents, and the "other collateral" hereinafter discussed, are then pledged by the SPE as collateral to the trustee under the indenture under which the securitization bonds are issued.

The "other collateral" is typically composed of a "Collection Account," which is established by the SPE as a trust account to be held by the trustee to ensure the payment of principal, interest, and other costs associated with the securitization bonds in full and on a timely basis. The "other collateral" typically also includes any other credit enhancements provided by or on behalf of the SPE, as well as a pledge of the SPE's rights under the transaction documents, including the agreement for the sale of the securitization property, the servicing agreement, and an administration agreement (whereby the sponsoring utility provides administration services to the SPE). The "other collateral" may also include an inter-creditor agreement or agreements that establishes conventions for allocating payments from customers received by the servicer among the SPE, the servicer, the trustee for the securitization, and the trustee for any other existing or future securitizations. The utility also typically covenants that it will not undertake another securitization transaction or execute any trade receivables purchase and sale agreement unless such inter-creditor agreement is amended to cover those other financing transactions.

<u>Servicing Considerations:</u>

The servicing function in a utility securitization is in many respects no different from what is required for a more standard securitization. The utility, in accordance with its regular operating procedures, will be responsible for meter readings, obligor billing, collecting payments from obligors and resolving billing disputes. Additionally, the servicer will be required to generate periodic reports on the collateral pool, determine allocation of cash collections and prepare distribution instructions all in accordance with the transaction documentation. Finally, the servicer/utility will be responsible for monitoring the performance of the transaction and applying to the Commission for and implementing true-ups as required (to the extent appropriate).

There are, however, some distinctions in the servicing arrangements in utility securitizations, principally, the ability of the utility to resign as servicer. In most securitizations, the servicer may resign effective upon the appointment of a replacement. In utility securitizations, given the importance of the utility's infrastructure, such as its ability to perform meter reads and its billing and collection services, utilities acting as servicers in utility securitizations typically cannot voluntarily resign. The AB 1054 and

SB 901 securitizations by SCE and PG&E have required Commission approval to resign as servicer.

The servicing fee for utility securitizations is typically calculated as a percentage of the original principal balance because, unlike that for a more standard securitization with a self-liquidating pool of securitized assets, the number of accounts serviced remains constant, and servicing costs are level over the life of the utility securitization.

Table 2-1 provides a snapshot of annual servicing fees for the initial servicer on various recent utility securitizations as a percentage of the original principal balance outstanding.

TABLE 2-1
RECENT UTILITY SECURITIZATION ANNUAL SERVICING FEE PERCENTAGES

Line No.	Deal	Annual Servicing Fee (% of Initial Principal Balance)
1	DUK 2024-1	0.05%
2	VIRPFS 2024-1	0.05%
3	EVGR 2024-A	0.05%
4	AQNCN 2024-A	0.05%
5	PNM 2023-A	0.05%

As the cost of servicing should not be impacted by the financing amount of the securitization (variables that are more relevant include number of obligors, complexity of billing, bank account management), the servicing fees percentages are generally lower for larger transactions.

In the event of a servicing default by the origination company, the transaction documents typically allow the trustee (as instructed by the bondholders) to appoint a third party as replacement servicer. Replacement servicing fees in past utility securitization have generally been capped at around 0.60 percent of the initial principal balance, with higher amounts only permitted with the approval of the public utility commission that issued the related financing order and after ensuring such higher rate will not negatively impact the then-current rating of the bonds.

To my knowledge, there has never been a replacement servicer appointed in a utility securitization, due in part to the unique and essential role of the distribution utility.

Rating Agency Considerations:

Similar to more standard securitizations, the major rating agencies have all published ratings criteria for utility securitizations.

The strength of the support from the applicable legislative bodies, governmental agencies (including the public utility commission), the applicable legislation and the financing order are vital elements of the rating agency analysis. The rating agencies' transaction review will, accordingly, start with an analysis of the following key elements of the supporting legislative statutes and the financing order:

- Non-bypassability of the securitization charges;
- Bankruptcy-remote status for the SPE;
- A current property right in the rights established under the regulatory framework and financing order, which is established by the financing order and statute and transferred to the SPE pursuant to a true sale;
- The assignment of the SPE's rights to the trustee in a perfected first priority security interest;
- The terms of a true-up mechanism occurring with requisite frequency and subject only to mathematical review by the public utility commission;
- The irrevocability of the financing order;
- The state non-impairment pledge and reaffirmation of the state's pledge by the public utility commission; and
- Federal and state constitutional protections.

The next area of focus of the rating agencies is the credit enhancement structure for the utility securitization transaction. Given that the nature of the transferred asset supporting a utility securitization is different from the underlying asset in a more standard securitization, the approach to credit enhancement is also a little different. There is no excess spread or subordination through notes with lower designated credit ratings, and letters of credit or surety bonds are generally not used. While there typically is a small cash reserve account (0.5 percent of the initial debt balance), the real credit enhancement comes from the "true-up" mechanism. In other words, the performance of a utility securitization is primarily driven by the ability to accurately predict the future level of electricity consumption, delinquencies, and losses, and a nimble "true-up" mechanism that ensures timely payment of debt service and transaction expenses. For large investor—owned utilities, the size and diversity of the customer base, the small size of the securitization charge relative to the aggregate electric bill, the essentiality of the service provided by the utility, and the true-up mechanism ensure the high credit quality of utility securitizations and typically enable utility securitizations to receive the highest ratings from the rating agencies.

Another element of the rating agencies' analysis involves the breadth of the market to which the securitization charge will be applied and the extent to which the charge might be "bypassable" by the electric customers. In certain utility transactions, pre-defined classes of customers may be exempted from contributing to payment of debt service and associated transaction costs and expenses. Generally, such exemptions are very limited in nature, with the statute, as in the case of AB 1054, or the financing order specifying exactly which customer classes will be responsible for the securitization charges for the life of the utility securitization bonds. The financing order typically also specifies that customers that currently or at some future point may receive electric generation from a third -party, including alternative Energy Service Providers (ESP) and municipalities, will continue to be assessed the securitization charges for the life of the utility securitization bonds.

In the case of third-party-ESPs, they may provide a consolidated bill for their generation services as well as the tariffs (and the securitization charges) owed to the utility. Where this is the case, the ESP is typically liable to pay the tariff to the utility within a certain period of time regardless of whether it has received collections from the electric customer. As a result, the utility securitization may be exposed to credit risk on the ESP (i.e., the resulting loss of commingled tariffs in the event of the bankruptcy of an ESP). This risk is typically mitigated by imposing certain restrictions on: (a) the minimum credit quality of the ESP (investment grade or posting collateral such as letters of credit); and (b) the maximum length of time that an ESP may commingle funds before submitting payment to the utility. If the ESP fails to satisfy the minimum credit rating requirements or becomes delinquent in payments, direct and consolidated billing may cease and service and separate billing to the end-user-customer would be made for the tariff. While these arrangements largely mitigate the risks associated with third-party-ESPs, the ESP nevertheless is allowed to commingle funds for a number of days before making payment. To address this risk, the rating agency may prepare stressed cash flow runs that eliminate one or more months of collections per year from such third-party-ESPs at the utility's peak billing cycle.

Relative to more standard securitization transactions, the analysis of securitization bonds is necessarily somewhat more limited because the sole sources of payment are the securitization charge collections and other assets of the SPE pledged to the payment of the bonds. The rating agencies perform extensive analyses—often referred to as "stress tests"—on the cash flows of the underlying assets to assess whether interest will be paid in a timely fashion and principal will be fully repaid by the legal maturity date (although actual experience deviates significantly from predicted historical norms). Some of the key variables in this analysis include the impact of stressed variances between projected and actual electric consumption, collection delays (delinquencies) and charge-offs.

The rating agencies will also analyze the impact of the securitization charges on the ratepayers; a substantial securitization charge relative to the regular billed amount can be cause for concern. Rating agency stresses for this purpose will also include looking at customers falling out of the eligible ratepayer base (i.e., exempted customer classes, if any) and the total securitization charge as a percent of the customers' utility bills.

Utility securitization bonds backed by securitization property and financing orders have maintained their high ratings, even when the credit of the utility has been downgraded and/or the utility has entered bankruptcy, thus justifying the investors' confidence in the bonds.

<u>Accounting Considerations:</u>

While the utility has the ability to sell the securitization property from a legal true sale perspective, utility securitizations issued by utilities governed by U.S. GAAP generally do not meet the accounting requirements to recognize the transfer of the securitization property as a sale for accounting and instead recognized the associated assets and liabilities on the utility's balance sheet. There have been certain very limited instances where utility securitizations have been determined to meet the accounting requirements for off-balance sheet treatment.

Tax Considerations:

The Internal Revenue Service in 2005 issued a revenue procedure (2005-62) that states that a utility entering into a "qualifying securitization" (which among other things requires that the issuing SPE is capitalized by an equity contribution from the utility of no less than 0.5 percent of the aggregate principal amount of the financing) will receive the following tax treatment:

- Be treated as not recognizing gross income in connection with: (i) the receipt of the financing order; (ii) the receipt of cash or other consideration in exchange for the transfer of the intangible property right created under the financing order; or (iii) the receipt of cash or other consideration in exchange for securitized instruments issued by the SPE;
- The securitized instruments will be treated as obligations of the utility; and
- The securitization charges are gross income to the utility.

Revenue Procedure 2005-62 clarifies that a typical qualifying utility securitization will avoid recognition by the utility of gross income upon receipt from the SPE of the net proceeds of the securitization bonds as the sales price of the securitization property, and treats the securitization-related customer charges as gross income to the utility under its usual method of accounting.

In February 2024, the Internal Revenue Service issued Revenue Procedure 2024-15, which modified Revenue Procedure 2005-62 for the purpose of authorizing "debt-for-tax" treatment for a utility if the utility utilizes a State sponsored financing entity (instead of a wholly-owned utility subsidiary) as the SPE/issuer. It is my understanding that the new revenue procedure was issued to allow for a state entity to act as the issuing entity for the bonds while still allowing the sponsor utility to receive the same tax treatment as if the issuing entity were a wholly-owned subsidiary.

C. Securitization Market Size and Investor Base

1. Size of the Securitization Market

The first public asset-backed securities were issued in 1985 by Sperry Lease Finance, which securitized computer leases. A variety of asset types have been securitized in the public markets since then, including credit card receivables, trade receivables, automobile loans and leases, student loans, home equity loans and lines of credit, equipment leases, manufactured housing contracts, unsecured consumer loans and a number of other less traditional assets. The following table shows a breakdown of 2023 U.S. public securitization issuance by asset type.

TABLE 2-2
2023 U.S. SECURITIZATION ISSUANCE BY ASSET TYPE

Line No.	Asset Type	Volume ($ Billions)	Percentage (%)
1	Auto	138.8	52.9
2	Other Esoteric	64.9	24.7
3	Equipment	22.5	8.6
4	Credit Cards	22.0	8.4
5	Utility	7.8	2.9
6	Student Loan	6.6	2.5
7	Total	262.8	100.0

Note: Source: Finsight as of 05/30/2024. Please note that total is rounded. Amounts shown are as presented on Finsight.

The securitization market has settled into a mature market since the financial crisis, with issuances totaling $262.8 billion in 2023, which was up 5 percent from $249.1 billion in 2022 and down 14 percent from $290.8 billion in 2021.[8]

The tone of the ABS 144A market improved through second half of 2023 and the strength has continued through first quarter of 2024. The first five months of the year saw robust investor engagement in new issue deals, which resulted in healthy oversubscription levels in securitizations across a variety of asset classes. This in turn granted issuers a greater ability to

8 Source: Finsight as 05/30/2024.

tighten in pricing throughout marketing processes. This momentum has led to historically high levels of ABS issuance with a weekly run rate nearing (and oftentimes surpassing) ~$10 billion. As of the date of this testimony, the new issue market remains strong, with investors actively deploying capital across ABS subsectors. The most recent utility securitization, Duke Energy South Carolina priced in mid-April 2024. The $177 million transaction was one ~10-year tranche that priced at a spread of 85 basis points to treasuries. While the transaction size in the securitization market typically ranges from approximately $100 million to $2.0 billion, there are a number of examples of larger securitizations completed with a deal size exceeding $2.0 billion (Table 2-3).

TABLE 2-3
LARGEST STANDARD (NON-UTILITY) SECURITIZATION TRANSACTIONS (2011-2024 YTD)

Line No.	Rank	Transaction	Issuer	Date	Asset Class	Rating(sf)	Issuance ($mm)
1	1	BVABS 2023-CAR3	Bayview Asset Management	Jun-23	Prime Auto Loan	AAA-B	$4,432
2	2	SSC 2018-1	Sprint	Mar-18	Spectrum	BBB	$3,937
3	3	SSC 2016-1	Sprint	Oct-16	Spectrum	BBB	$3,500
4	4	AMXCA 2021-1	Amex	Nov-21	Credit Card	AAA	$2,750
5	5	USRE 2021-1	USAA	Oct-21	Triple Net Lease	AA-/A-	$2,691
6	6	SCFT 2014-A	Springcastle	Sep-14	Consumer	AA - B	$2,600
7	7	COMET 2022-A1	Capital One	Jun-22	Credit Card	AAA	$2,500
8	8	WEN 2015-1	Wendy's	May-15	Whole-Bus	BBB	$2,425
9	9	AMXCA 2017-1	Amex	Feb-17	Credit Card	AAA/BBB	$2,399
10	10	DNKN 2021-1	Dunkin Brands	Oct-21	Whole-Bus	BBB	$2,350
11	11	TALNT 2021-1	Toyota	Mar-21	Prime Auto Loan	AAA	$2,250
12	12	FORDR 2018-1	Ford	Jan-18	Prime Auto Loan	AAA-A	$2,186

Note: Source: Finsight as of 05/30/2024.

2. Size of the Utility Securitization Market and Investor Base

Over $85 billion of utility securitization bonds have been issued successfully by electric utilities in various states since inception of the sector in 1995 (Table 2-4).

TABLE 2-4
HISTORICAL US UTILITY SECURITIZATION TRANSACTIONS (1995-2024YTD)

Line No.	Issuer	Amount ($)	Pricing Date
1	Duke Energy Corp	177,365,000	04/16/2024
2	Evergy Inc	331,127,000	02/14/2024
3	Dominion Energy Inc (fka Dominion Resources Inc)	1,281,900,000	02/05/2024
4	Algonquin Power & Utilities Corp	305,490,000	01/18/2024
5	CMS Energy Corp	646,000,000	12/05/2023
6	PNM Resources Inc	343,000,000	11/07/2023
7	DTE Energy Co	602,000,000	10/18/2023
8	Centerpoint Energy Inc	$341,000,000	6/21/2023
9	Atmos Energy Kansas	95,000,000	6/9/2023
10	Southern California Edison	775,000,000	4/19/2023
11	Entergy Corp	1,491,000,000	3/21/2023
12	Texas Public Finance Authority	3,536,310,000	3/9/2023
13	Entergy Corp	209,000,000	12/9/2022
14	Brazos Electric Power Cooperative	713,000,000	12/8/2022
15	Denton County Electric Cooperative Inc (CoServ)	460,000,000	12/7/2022
16	United Electric Cooperative Inc (UEC)	452,000,000	12/6/2022
17	Pacific Gas & Electric	983,000,000	11/18/2022
18	One Gas	336,000,000	11/9/2022
19	Long Island Power Authority	882,070,000	9/20/2022
20	American Electric Power Co Inc	697,000,000	8/30/2022
21	One Gas	1,354,000,000	8/18/2022
22	Pacific Gas & Electric	3,900,000,000	7/13/2022
23	OGE Energy Corp	762,000,000	7/8/2022
24	Cleco Partners LP	452,000,000	6/9/2022
25	Electric Reliability Council of Texas (ERCOT)	2,116,000,000	6/8/2022
26	Entergy Corp	3,194,000,000	5/11/2022
27	Pacific Gas & Electric	3,600,000,000	5/3/2022
28	Entergy Corp	291,000,000	3/24/2022
29	DTE Energy Co	236,000,000	3/11/2022
30	Edison International	533,000,000	2/8/2022
31	Rayburn Electric Cooperative	908,000,000	2/4/2022
32	Duke Energy Carolinas	770,000,000	11/17/2021
33	Duke Energy Progress	237,000,000	11/17/2021
34	Pacific Gas & Electric	860,000,000	11/4/2021
35	WEC Energy Group	119,000,000	5/4/2021
36	Southern California Edison	338,000,000	2/17/2021
37	AEP Texas Restoration Funding LLC	235,282,000	9/11/2019
38	Public Service New Hampshire Funding LLC.	635,663,200	5/1/2018
39	Duke Energy Florida Project Finance LLC	1,294,290,000	6/15/2016
40	Entergy New Orleans Storm Recovery Funding I	98,730,000	7/14/2015
41	Dept. of Business, Economic Development, and Tourism/Hawaii Electric	150,000,000	11/13/2014
42	Louisiana Utilities Restoration Corporation Project/ELL	243,850,000	7/29/2014
43	Louisiana Local Government System Restoration/EGSL	71,000,000	7/29/2014
44	Consumers 2014 Securitization Funding LLC	378,000,000	7/14/2014
45	Appalachian Consumer Rate Relief Funding LLC	380,300,000	11/6/2013
46	Ohio Phase-In-Recovery Funding LLC	267,408,000	7/23/2013
47	FirstEnergy Ohio PIRB Special Purpose Trust	444,922,000	6/12/2013
48	AEP Texas Central Funding III	800,000,000	3/7/2012
49	Centerpoint Energy Transmission Bond Co. IV	1,695,000,000	1/11/2012
50	Entergy Louisiana Investment Recovery Funding I, LLC	207,156,000	9/15/2011

TABLE 2-4
HISTORICAL US UTILITY SECURITIZATION TRANSACTIONS (1995-2024 YTD)
(CONTINUED)

Line No.	Issuer	Amount ($)	Pricing Date
51	Entergy Arkansas Energy Restoration Funding LLC	124,100,000	8/11/2010
52	Louisiana Utilities Restoration Corporation Project/ELL	468,900,000	7/15/2010
53	Louisiana Utilities Restoration Corporation Project/EGSL	244,100,000	7/15/2010
54	MP Environmental Funding LLC	64,380,000	12/16/2009
55	PE Environmental Funding LLC	21,510,000	12/16/2009
56	CenterPoint Energy Restoration Bond	664,859,000	11/18/2009
57	Entergy Texas Restoration Funding	545,900,000	10/29/2009
58	Louisiana Public Facilities Authority	278,400,000	8/20/2008
59	Louisiana Public Facilities Authority	687,700,000	7/22/2008
60	Cleco Katrina/Rita Hurricane Recovery Funding LLC 2008	180,600,000	2/28/2008
61	CenterPoint Energy Transition Bond Company III	488,472,000	1/29/2008
62	Entergy Gulf States Reconstruction Funding I, LLC	329,500,000	6/22/2007
63	RSB BondCo LLC (BG&E sponsor)	623,200,000	6/22/2007
64	FPL Recovery Funding LLC	652,000,000	5/15/2007
65	MP Environmental Funding LLC	344,475,000	4/3/2007
66	PE Environmental Funding, LLC	114,825,000	4/3/2007
67	AEP Texas Central Transition Funding II	1,739,700,000	10/4/2006
68	JCP&L Transition Funding II	182,400,000	8/4/2006
69	Centerpoint Energy Series A	1,851,000,000	12/9/2005
70	PG&E Energy Recovery Funding LLC Series 2005-2	844,461,000	11/3/2005
71	West Penn Power	115,000,000	9/22/2005
72	PSE&G 2005-1	102,700,000	9/9/2005
73	Massachusetts RRB Special Purpose Trust 2005-1	674,500,000	2/15/2005
74	PG&E Energy Recovery Funding LLC Series 2005-1	1,887,864,000	2/3/2005
75	Rockland Electric Company	46,300,000	7/28/2004
76	Oncor (TXU) 2004-1	789,777,000	5/28/2004
77	Atlantic City Electric	152,000,000	12/18/2003
78	Oncor 2003-1	500,000,000	8/14/2003
79	Atlantic City Electric	440,000,000	12/11/2002
80	JCP&L Transition Funding LLC	320,000,000	6/4/2002
81	CPL Transition Funding LLC	797,334,897	1/31/2002
82	PSNH Funding LLC 2	50,000,000	1/16/2002
83	Consumers Funding LLC	468,592,000	10/31/2001
84	CenterPoint Energy Transition Bond Company I	748,987,000	10/17/2001
85	Western Mass Electric	155,000,000	5/14/2001
86	PSNH Funding LLC	525,000,000	4/20/2001
87	CL&P Funding LLC	1,438,400,000	3/27/2001
88	Detroit Edison 2001-1	1,750,000,000	3/2/2001
89	PECO 2001-A	805,500,000	2/15/2001
90	PSE&G 2001-A	2,525,000,000	1/25/2001
91	PECO 2000-A	1,000,000,000	4/27/2000
92	West Penn Power	600,000,000	11/3/1999
93	Pennsylvania Power & Light	2,420,000,000	7/29/1999
94	Boston Edison	725,000,000	7/27/1999
95	Sierra Pacific Power	24,000,000	4/8/1999
96	PECO Energy	4,000,100,000	3/18/1999
97	Montana Power	64,000,000	12/22/1998
98	Illinois Power	864,000,000	12/10/1998
99	Commonwealth Edison	3,400,000,000	12/7/1998
100	San Diego Gas & Electric	657,900,000	12/4/1997

TABLE 2-4
HISTORICAL US UTILITY SECURITIZATION TRANSACTIONS (1995-2024 YTD)
(CONTINUED)

Line No.	Issuer	Amount ($)	Pricing Date
101	Southern California Edison	2,463,000,000	12/4/1997
102	Pacific Gas & Electric	2,901,000,000	11/25/1997
103	Puget Sound Energy	35,000,000	7/30/1997
104	Puget Sound Power & Light	202,000,000	6/8/1995
	Total	$85,327,300,097	

Note: Source: Bloomberg, Finsight, Company Filings, Press Releases and Other Publicly Available Information as of 05/30/2024.

Utility securitizations by definition are episodic in nature, raising funds in a very specific amount and for a specific purpose. The size of the above historical transactions is therefore not necessarily a reflection of market capacity at that time. Furthermore, in several cases involving large transactions, the required funding target was achieved in more than one issuance over a period of time (e.g., Philadelphia Electric Company (PECO) in 1999 and 2000, Oncor Electric Delivery in 2003 and 2004, PG&E in 2005, CenterPoint Energy Houston Electric in 2005 and 2008, Long Island Power Authority (LIPA) in 2013, 2016, 2015, 2017, 2022 and 2023, and PG&E with two SB 901 transactions in 2022). Finally, certain transactions with similar characteristics (i.e., a charge on a customer invoice) have been issued in vary large amounts. In 2002, the California Department of Water Resources (DWR) was authorized to issue up to approximately $13.4 billion of bonds (Power Supply Revenue Bonds), and ultimately issued $11.5 billion to repay various entities for purchases of power at above market rates during the California energy crisis. The DWR structure was not technically a securitization as there was no bankruptcy-remote SPE, and the transactions were therefore rated below AAA. However, the underlying security for the Power Supply Revenue Bonds (i.e., the right to bill and collect statutorily authorized, non-bypassable charges imposed by CPUC upon customers of the investor-owned utilities in amounts sufficient to repay the bonds) is fundamentally the same security as the security for utility securitizations. In 2019, DWR was authorized under AB 1054 to issue additional wildfire cost recovery bonds using the same security structure.

TABLE 2-5
LARGEST UTILITY SECURITIZATION TRANSACTIONS (1997-2007)

Line No.	Rank	Transaction	Utility	Date	Commission State	Issuance ($mm)
1	1	PECO	PECO Energy	Mar-99	Pennsylvania	$4,000
2	2	ComEd	Com. Edison	Dec-98	Illinois	$3,400
3	3	PG&E-1	PG&E	Nov-97	California	$2,901
4	4	PSE&G-1	PSE&G	Apr-00	New Jersey	$2,525
5	5	SCE-1	SCE	Nov-97	California	$2,463
6	6	PP&L-1	PA Power & Light	Jul-99	Pennsylvania	$2,420
7	7	PG&E	PG&E	Jan-05	California	$1,888

Note: Source: Finsight as of 05/30/2024.

TABLE 2-6
LARGEST UTILITY SECURITIZATION TRANSACTIONS (2008-2024 YTD)

Line No.	Rank	Transaction	Utility	Date	Commission State	Issuance ($mm)
1	1	PCG 2022-B	PG&E Corp	Jul-22	California	$3,900
2	2	PCG 2022-A	PG&E Corp	May-22	California	$3,600
3	3	TNGSFC 2023	Texas Public Finance Authority	Mar-23	Texas	$3,522
4	4	LCDA 2022-ELL	Entergy Corp	May-23	Louisiana	$3,194
5	5	ERCOTT 2022-1	ERCOT	Jun-22	Texas	$2,116
6	6	UDSA 2013-1	LIPA	Dec-13	New York	$2,022
7	7	CNL 2012-1	CenterPoint Texas	Jan-12	Texas	$1,695
8	8	LCDA 2023-ELL	Entergy Corp	Apr-23	Louisiana	$1,491
9	9	ODFA 2022-ONG	One Gas Inc	Nov-22	Oklahoma	$1,354
10	10	DUK	Duke Energy	Jun-16	Florida	$1,294
11	11	VIRPFS 2024-1	Dominion	Feb-24	Virginia	$1,282
12	12	UDSA 2015	LIPA	Oct-15	New York	$1,002

Note: Source: Finsight as of 05/30/2024.

A broad range of investors have participated in utility securitization bond issues to date, including domestic and international banks, institutional and retail trust funds, money managers, investment advisors, pension funds, insurance companies, securities lenders, state trust funds, and corporate cash managers. Traditional utility unsecured, first mortgage bond and municipal investors have also participated broadly, as some perceive utility securitization bonds as a highly rated substitute for the product they traditionally purchase. In recent transactions, to broaden the potential investor base for utility securitization bonds, certain issues have been marketed as “green” bonds based either on the strength of the use of proceeds, as was the case in PG&E’s two prior AB 1054 transactions (that have priced), or the use of proceeds and a second party opinion, as was the case in SCE’s second and third AB 1054 transactions and one completed for the LIPA in New York in 2022 and 2023.

Utility securitization bonds are a well-established asset class, and broadly understood by a diverse set of investors. Utility securitization bonds backed by securitization property and financing orders have maintained their high ratings, even when the credit of the utility has been downgraded or the utility has entered bankruptcy, thus justifying investors’ confidence in the bonds.

The interest income received is taxable for federal income tax purposes for investors in the vast majority of these utility securitizations (some have been tax-exempt for state purposes), but there have also been some transactions issued into the municipal market where interest is tax-exempt for federal tax purposes.

D. Structuring, Pricing, Marketing and Upfront Transactional Expenses

1. Structuring Utility Securitizations

The debt service and scheduled amortization for utility securitization bonds are derived based on the expected collections to be received from the securitization charges. The weighted average life of a securitization bond refers to the average amount of time an investor is expected to invest the full amount of principal, weighted by the amount of principal received in each period. In contrast, the average life for a bullet maturity security (the typical corporate bond principal payment structure) is equal to the period of time between the issuance date and the maturity date. The preliminary structure for this issuance is shown in Table 2-7:

TABLE 2-7
INDICATIVE STRUCTURE

Line No.	Class	Balance	Coupon	Price	Yield	Average Life	First Principal	Last Principal
1	A-1	$670,250,000	5.51%	100.000	5.51%	2 yrs	1/1/2026	1/1/2029
2	A-2	876,480,000	5.24%	100.000	5.24%	5 yrs	1/1/2029	7/1/2032
3	A-3	824,925,000	5.36%	100.000	5.36%	9 yrs	7/1/2032	1/1/2035
4	Total	$2,371,655,000	5.33%	100.000	5.33%	5.6 yrs		

Please note that these terms are preliminary and estimated based on today's market conditions. The final terms and conditions of the utility bonds will not be known until after they have been priced in the marketplace. Investor demand at the time of pricing will determine market clearing interest rates and the final structure offered to investors. Therefore, the preliminary structure and pricing information is preliminary and subject to change, and the actual structure and pricing will differ, and may differ materially from the preliminary structure.

Frequently, and especially in the case of utility securitizations with long tenors, the transaction will be structured as multiple tranches with various scheduled average lives ranging potentially from 2 to approximately 30 years. The expected final principal payment of the vast majority of utility securitizations occurs within 20 years, with the furthest out expected final principal payment occurring in year 30 for the PG&E 2022 SB 901 transaction. The legal maturity of the last maturing tranche of securitized utility bonds will be approximately 1 to 2 years after the expected final payment date of the last maturing bond.

Certain utility securitizations have been designed to allow a sole SPE to issue multiple series of bonds causing the bonds not to be treated as "asset-backed securities" within the meaning of SEC Regulation AB. This might, under certain circumstances, have advantages for marketing of longer tenor bonds.

TABLE 2-8
EXPECTED FINAL PAYMENT DATES OF RECENT UTILITY SECURITIZATIONS

Line No.	State	Utility	Pricing Date	Expected Final Payment Date (Years)
1	South Carolina	Duke Energy Corp	4/16/2024	20
2	Missouri	Evergy Inc	2/14/2024	14
3	Virginia	Dominion Energy Inc	2/5/2024	7
4	Missouri	Algonquin Power & Utilities Corp	1/18/2024	13
5	Michigan	CMS Energy Corp	12/5/2023	7

Debt service in utility securitizations is typically paid semi-annually. As monthly cash flows can be less predictable, a longer payment period can help smooth variations in the cash flows and ensure payment of debt service. However, shorter payment periods reduce the time collections are held by the SPE earning lower short-term rates while the SPE pays higher coupons on the securitized debt.

The structuring advisor/lead underwriter(s) will typically assist the utility by preparing financial models to assess various financing and structuring alternatives and the economic impact of such alternatives, while considering execution viability from both a rating agency and marketing perspective. The structuring advisor/lead underwriter(s) will also assist the utility in optimizing the overall amortization schedule to meet its financing goals.

An important element of the transaction process is obtaining the highest ratings on the utility securitization bonds, which will generally need to be rated by at least two Nationally Recognized Statistical Rating Organizations (rating agencies). The utility securitization bonds will be structured to achieve the highest ratings possible, and the structuring of the bonds will largely be driven by the rating agencies' requirements. The utility, together with the structuring advisor/lead underwriter(s), will prepare written presentations that will be delivered through in-person meetings with the rating agencies, to discuss the credit framework and strength of the proposed utility securitization.

Each rating agency asked to rate the bonds will review the utility's forecasting, billing and collections operations and capabilities. They will review the utility's operational capabilities as servicer and its related systems. The rating agencies will analyze the constituent documents and seek extensive opinions in reviewing the transaction and will review those matters with the utility, the structuring advisor/lead underwriter(s) and counsel. The structuring advisor/lead underwriter(s) will be required to prepare various cash flow stress scenarios to demonstrate that the bonds will be repaid under stressed cash flow projections. There will be extensive review of the utility securitization bond structures by the rating agencies.

2. Marketing and Pricing Utility Securitizations

The securitization bonds will be offered for sale to investors through one or more lead underwriter(s), each of which should have deep experience in the marketing of utility securitization bonds in various markets. The interest rate or bond coupon is a function of the market conditions at the time the bonds are sold and is influenced not only by general market conditions but also by factors including the size of the offering, ratings of the bonds and the number and quality of competitive bond offerings coming to the market at or around the same time. To my knowledge, the majority of utility securitizations to date have been sold through a negotiated sale process, although the Florida Public Service Commission (FPSC) used a quasi-competitive process for the sale of its hurricane recovery bond for the benefit of Florida Power & Light in 2007. The FPSC reverted to a negotiated sale process for the Duke Energy Florida securitization in 2016.

Information will be provided to investors regarding the utility securitization bonds. Following the delivery of the preliminary prospectus and other marketing materials, typically including an investor presentation, the utility and the lead underwriter(s) will work together to generate investor attention by informing investors of the transaction structure, including callability[9] and terms and answering any questions from investors. The purpose of this process is to garner investor interest, so that pricing will result in the lowest available cost of funds.

9 The vast majority of utility securitization bonds are not callable, or subject to redemption before reaching the date of their stated maturity, with the exception of the utility securitization bonds issued by LIPA, as well as the notable exception of a utility securitization, issued on March 23, 2023, on behalf of the Texas Natural Gas Securitization Finance Corporation that included a call feature granting the issuer the option to redeem the bonds on or before April 1, 2026 at a “make whole redemption price.”

The lead underwriter(s) will market the utility securitization bonds to a broad investor base. As stated above, utility securitization bonds are a well-established and well-understood asset class. Moreover, a wide array of investors have traditionally invested in prior utility securitization bonds, including, money managers, banks, insurance companies, and pension funds. Those investors are active in both the securitization and corporate sectors, and the marketing plan would entail marketing to investors from both spaces.

During the pre-marketing phase of the transaction, the lead underwriter(s) will disclose a fixed rate benchmark index and preliminary credit spread ranges relative to the benchmark rate for each tranche, in response to which investors provide indications of interest. The lead underwriter(s) will be charged with keeping the master record (known as "the investor book") in which all indications of interest received by the lead underwriter(s) from potential investors are recorded.

The objective in setting the preliminary credit spread ranges is to establish a level sufficient to generate enough demand to allow all bonds to be sold, without setting spreads at a level higher than necessary.

The benchmark index used to price utility securitizations is typically either Treasuries or U.S. Swaps. The respective term of the benchmark index for each tranche typically matches the average life of the tranche.

The Treasury benchmark reflects the "risk-free" yield investors generally associate with U.S. Treasury securities, while the U.S. Swap benchmark reflects the yield demanded by investors for non-Treasury securities of similar term.

All recent utility securitizations have used fixed rate benchmarks. Fixed rate bonds enable the costs and benefits to be evaluated in advance and ensure roughly equal charges over time.

The credit spreads are the margins over the benchmark indices that investors require to reflect their understanding of the risk of credit default on the bonds. The credit spread over the benchmark yield is commonly measured in hundredths of a percentage, or basis points. The credit spread for each tranche of utility securitization bonds is determined through the marketing and pricing process, as institutional investors assess the credit risk of the particular bonds and decide how low a credit spread is acceptable, given the quality and supply of other competing debt securities they could purchase at that time. Investors also may consider a minimum absolute yield for the securities being marketed.

At the official launch of the transaction, the lead underwriter(s) will disclose specific credit spreads for each tranche, and investors will be invited to place orders through the lead underwriter(s) for the amount and specific tranches of securitization bonds they are willing to purchase, at certain prices and securitization bond coupon rates.

The lead underwriter(s), exercising professional judgment based on the amounts of orders received from potential investors, current benchmark index environment and with the express concurrence of the utility, may adjust the credit spreads which dictate the bond coupon rates to ensure maximum distribution of the securitization bonds at the lowest bond yields consistent with a fixed price offering. If the tranche is oversubscribed, the lead underwriter(s) may lower the credit spread, provided that this adjustment does not decrease the aggregate investor interest below the size of the tranche. If the tranche is undersubscribed, the lead underwriter(s) may increase the coupon to attract sufficient investor orders to sell the entire tranche. In the event there are no market clearing coupons and prices for one or more tranches, the transaction may be restructured in order to ascertain the tranches and market clearing interest rates required to sell all the utility securitization bonds to investors.

Taking into account the actual demand for the utility securitization bonds on the day of pricing, the lead underwriter(s), pursuant to the terms of an executed underwriting agreement, will agree to purchase the utility securitization bonds at specified prices and coupon rates with such bonds then resold by the lead underwriter(s) to the identified investors.

In summary, it is through the marketing and price discovery process that the actual market for the utility securitization bonds is determined. It should be noted that this determination is specific to the issue of the utility securitization bonds in question. It is based on the actual investor orders for particular securitization bonds on the actual day of pricing. The Commission's representative will be updated continuously throughout the marketing and pricing process. It is this process that provides assurance that the bonds are being sold at the lowest rates available.

3. Upfront Transaction Expenses

Upfront transactional expenses on recent utility securitizations have ranged from approximately 1.00 percent – 4.00 percent of the original principal amount of the utility securitization bonds (*see* Table 2-9). These expenses will include, but are not limited to, fees in connection with legal services, accountants, advisors, underwriters, trustees, rating agencies, SPE/servicer setup costs, SEC registration and printers. Depending on the original principal amount of the utility securitization, some of these expenses may benefit from economies of scale in a large issuance.

TABLE 2-9
RECENT PUBLICLY DISCLOSED UTILITY ASSET BACKED SECURITIES ISSUANCE COSTS

Line No.	Issue Date	State	Utility Sponsor	Size ($000)	Underwriting Fees (%)	Total Cost ($)	Total Cost (% of Size)
1	Apr-24	SC	Duke	177,365	0.40%	6,048,330	3.41%
2	Feb-24	MO	Evergy	331,127	0.46%	8,175,000	2.47%
3	Feb-24	VA	Dominion	1,281,900	0.45%	5,745,776	0.98%
4	Jan-24	MI	Algonquin	305,490	0.46%	8,914,000	2.92%
5	Jun-23	IN	CenterPoint	341,450	0.40%	4,772,596	1.40%
6	Jun-23	KS	Atmos	95,000	0.53%	4,945,258	5.21%
7	Apr-23	CA	SCE	775,419	0.40%	6,649,500	0.86%
8	Jun-23	LA	Entergy	1,491,000	0.47%	11,436,977	0.76%
9	Dec-22	CA	PG&E	983,362	0.40%	8,362,000	0.85%
10	Nov-22	KS	One Gas	336,000	0.40%	8,640,495	2.57%

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

TRANSACTION OVERVIEW

WITNESS: MONICA KLEMANN

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A. Introduction

This chapter describes Pacific Gas and Electric Company's (PG&E) proposed Wildfire Rate Relief Bond financing transaction and the considerations that determine the proposed transaction structure. Attachment A to the application is a proposed form of financing order (Form of Financing Order) for the proposed transaction as described in this chapter. As noted in Chapter 1, Introduction (M. Becker), although the proposed securitization differs from PG&E's prior Assembly Bill (AB) 1054 Capex securitization transactions with respect to the type of costs to be financed, it otherwise closely tracks the framework for PG&E's prior AB 1054 transactions.[1] A summary of the Third AB 1054 Securitization is included in Section VI of the Application.

B. Overview of AB 1054

On July 12, 2019, Governor Newsom signed into law AB 1054, which amended Division 1, Part 1, Chapter 4, Article 5.8 of the California Public Utilities Code (Pub. Util. Code) (Sections 850-850.8) and authorized the issuance of recovery bonds. Some of the relevant provisions of Article 5.8 (as amended, Article 5.8) are set forth below.

- <u>Recovery Bond Authorization and Customer Benefit</u> – The Commission may issue a financing order authorizing the recovery of costs and expenses: (A) if an electrical corporation submits an application for recovery of costs and expenses related to catastrophic wildfires in a proceeding to recover costs and expenses in rates, and the Commission finds that some or all of the costs and expenses identified in the electrical corporation's application are

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[1] See Initial AB 1054 Securitization approved by the California Public Utilities Commission (Commission) in Decision (D.) 21-06-030, Financing Order Authorizing the Issuance of Recovery Bonds Pursuant to AB 1054, the Second AB 1054 Securitization approved by the Commission in (D.) 22-08-004, Financing Order Authorizing the Issuance of Recovery Bonds Pursuant to AB 1054, and the Third AB 1054 Securitization approved by the Commission in (D.) 24-02-011, Financing Order Authorizing the Issuance of Recovery Bonds Pursuant to AB 1054.

just and reasonable pursuant to Section 451; and (B) the issuance of the Wildfire Rate Relief Bonds and the imposition and collection of Wildfire Rate Relief Fixed Recovery Charges (WRRFRC): (1) are just and reasonable; (2) are consistent with the public interest; and (3) the recovery of recovery costs through the designation of WRRFRCs and any associated Fixed Recovery Tax Amounts (FRTA), and the issuance of Wildfire Rate Relief Bonds would reduce, to the maximum extent possible, the rates on a present value basis that consumers would pay as compared to the use of traditional utility financing mechanisms.[2]

- Non-Bypassable Charges – The Commission can impose non-bypassable charges (which Article 5.8 refers to as "fixed recovery charges," i.e., the WRRFRCs) on consumers to pay the principal, interest, and other financing costs (as defined in Section 850(b)(4)), and any associated "fixed recovery tax amounts" (as defined in Section 850(b)(8), i.e., the FRTAs). Except for a limited number of exemptions, the WRRFRCs and FRTAs are applicable to all existing and future electric consumers in PG&E's service territory as it exists as of the date of the financing order (PG&E's Service Territory).
- No Debt or Liability of the State of California (state of California or State) – Neither the state of California nor any political subdivision thereof will be liable for any amounts associated with the Wildfire Rate Relief Bonds, the WRRFRCs, or the FRTAs, and the State's credit and taxes shall not be pledged to pay for the Wildfire Rate Relief Bonds, WRRFRCs, FRTAs, or any associated costs.
- Periodic True-Up Adjustments – There shall be periodic True-Up adjustments of the WRRFRCs using the True-Up mechanism approved by the Commission in the financing order (which shall be made at least annually and may be made more frequently, if required) as necessary to correct for any overcollection or undercollection of the WRRFRC revenues authorized by the financing order and to otherwise ensure the timely and complete payment and recovery of the Wildfire Rate Relief Bond principal and interest, and other Ongoing Financing Costs (as defined below) over the authorized repayment term.

[2] Chapter 4, Customer Benefits (D. Raman), provides the statutory analysis of securitization compared against traditional utility financing.

- Irrevocable Charges – The Commission's financing order authorizing Wildfire Rate Relief Bonds, the WRRFRCs, and the FRTAs shall be irrevocable by future Commissions.
- Current Property Right – Article 5.8 creates a separate and current property right (Recovery Property) to receive the revenues from the non-bypassable WRRFRCs, including all rights to obtain adjustments to the WRRFRCs, and to all revenues, collections, claims, payments, moneys, or proceeds of or arising from the WRRFRCs.
- State Pledge – The state of California pledges and agrees with PG&E, owners of Recovery Property, Special Purpose Entities (SPE) that issue Wildfire Rate Relief Bonds, and holders of Wildfire Rate Relief Bonds that the State shall neither limit nor alter, except as otherwise provided with respect to the periodic True-Up adjustment pursuant to subdivision (g) of Section 850.1, the WRRFRCs, the FRTAs, Recovery Property, the financing order or rights under the financing order until the Wildfire Rate Relief Bonds, together with the interest on the Wildfire Rate Relief Bonds and other Ongoing Financing Costs are fully paid and discharged.
- Timeline for Financing Orders and Appeals – Sections 850.1, 1731, and 1756 establish the timeline for financing orders, rehearings and appeals. The Commission is to act on the application for a financing order within 120 days of when it is filed. Per Section 1731(b)(1), any application for rehearing must be filed within 10 days after the date of the issuance of the order or decision. Per Section 1731(d), the Commission is to issue its decision on any application for rehearing within 210 days of the filing for rehearing. Per Section 1756(a), any appeal must be made directly to the court of appeal or the California Supreme Court and must be filed within 30 days after the Commission denies rehearing.
- True Sale – Authorizes the transfer of Recovery Property by PG&E to another entity as an "absolute transfer" and "true sale," provided that the governing documentation expressly states that the transfer is an "absolute transfer" and a "true sale."
- Pledge of Property Right as Collateral – Authorizes the pledge of Recovery Property by its owner for the benefit of Wildfire Rate Relief Bond investors.

C. Timing and Sizing of the Proposed Transaction

PG&E requests authority for one or two series of Wildfire Rate Relief Bonds, up to the Authorized Amount, to be sized and marketed to minimize costs, consisting of an amount equal to the sum of: (1) the Wildfire Vegetation Management (VM) Expenses; and (2) the Upfront Financing Costs associated with the issuance of each series of Wildfire Rate Relief Bonds.[3] To attract a broad range of investors, each series may be divided into multiple tranches, each with its own scheduled final payment date and final legal maturity date. A final legal maturity date beyond the scheduled final payment date is a standard feature that allows for delays in scheduled principal payments due to variations in the cash flows from the recovery property.

The number of tranches, as well as the principal amount, scheduled final payment dates, and final legal maturity dates, interest rate, interest payment dates and other details of each tranche would be determined at the time each series of Wildfire Rate Relief Bonds is priced, to reduce, to the maximum extent possible, the rates that customers would pay.

PG&E proposes that the Wildfire Rate Relief Bonds will be fixed rate instruments, in order to ensure predictable savings to customers. PG&E further proposes that the Wildfire Rate Relief Bonds be repaid using a substantially level, mortgage style amortization, with an anticipated scheduled life of 10 years. The actual terms, including scheduled life, may vary depending on market conditions. Each separate Wildfire Rate Relief Bond tranche would be priced based on its average life (or maturity), determined by the principal amortization schedule at the time of issuance. The pricing would be a basis point spread over the swap rate or the rate on United States Treasury Notes with a comparable average life. The pricing of utility securitizations is discussed more generally in Chapter 2, Background on Utility Securitization (K. Niehaus).

Chapter 3, Attachment C sets forth the anticipated revenue requirement for the WRRFRCs, Ongoing Financing Costs, the FRTA amounts, and uncollectibles based on the Wildfire VM Expenses and current market conditions and the terms described in more detail below that have been analyzed and developed in consultation with Goldman Sachs, the structuring advisor to PG&E

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[3] The Upfront Financing Costs are set forth in Chapter 3, Attachment A. These are estimates, with final amounts to be included in the Issuance Advice Letter.

for this transaction. The final terms of the Wildfire Rate Relief Bonds authorized pursuant to this application will be set forth in the Issuance Advice Letter, in the form shown in Attachment 2 to the Form of Financing Order and with the concurrence of the Finance Team, as described below.

As further discussed below, based upon the advice of its structuring advisor and the current market conditions, and consistent with its prior securitizations under AB 1054, PG&E does not anticipate including additional credit enhancements for these Wildfire Rate Relief Bonds (e.g., overcollateralization, letters of credit, or bond insurance). However, if circumstances warrant the inclusion of additional credit enhancements, PG&E requests the flexibility to include any such credit enhancement in the Wildfire Rate Relief Bond structure. The inclusion of these features subsequently would be authorized through the Issuance Advice Letter process (described below).

PG&E presently anticipates issuing the proposed Wildfire Rate Relief Bonds during the first quarter of 2025, although this timing is subject to change.

D. Finance Team

PG&E proposes that the Commission use the same Finance Team as it established for the Initial AB 1054 Securitization, the Second AB 1054 Securitization, and the Third AB 1054 Securitization, and that the Finance Team have the same responsibilities as set forth in the financing orders authorizing those transactions, D.21-06-030, D.22-08-004, and D.24-02-011, respectively.[4] PG&E presents the various aspects of the proposed Wildfire Rate Relief Bonds and related transactions below with the expectation and understanding that the Finance Team will be involved in developing the final terms and that the final terms as set forth in the Issuance Advice Letter will be subject to the review and approval of the Finance Team to be delivered to PG&E on or before the date of pricing.

E. Proposed Transaction Structure

PG&E proposes a transaction structure for the Wildfire Rate Relief Bonds that is consistent with achieving the highest possible credit ratings on the Wildfire Rate Relief Bonds. This transaction structure is described below and is

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4 See D.21-06-030 at 47-50 and 116-118 (Ordering Paragraphs (OP) 2-4); D.22-08-004 at 49-51 and 111-113 (OPs 2-4); D.24-02-011 at 50-52 and 114-116 (OPs 2-4).

consistent with the structure adopted by the Commission for prior securitizations under AB 1054.The Wildfire Rate Relief Bonds will be issued by a wholly-owned SPE that will be capitalized by PG&E, as described below.[5] The Wildfire Rate Relief Bonds will be secured by “Recovery Property,” which Section 850(b)(11) defines as the right, title and interest of PG&E: (1) in and to WRRFRCs, including all rights to obtain adjustments to the WRRFRCs in accordance with Article 5.8 and a financing order; and (2) to be paid the amount that is determined in a financing order to be the amount that PG&E is lawfully entitled to receive pursuant to the provisions of Article 5.8 and the proceeds thereof, and in and to all revenues, collections, claims, payments, moneys, or proceeds of or arising from the WRRFRCs. Article 5.8 requires the Commission to set these rates at a level that provides sufficient funds to timely pay debt service on the Wildfire Rate Relief Bonds and other financing costs (as defined in Section 850(b)(4)). PG&E refers to these financing costs, which are associated with servicing the Wildfire Rate Relief Bonds and supporting the operations of the SPE, as “Ongoing Financing Costs.”

PG&E will transfer the Recovery Property, via a true sale and absolute transfer, to the SPE, which is legally separate and bankruptcy remote from PG&E. This ensures that if PG&E ever becomes bankrupt, the Recovery Property will not be included in PG&E’s bankruptcy estate. Rather, the revenues from the Recovery Property will continue to be available to pay the debt service on the Wildfire Rate Relief Bonds and other Ongoing Financing Costs. The Wildfire Rate Relief Bonds will be issued under an indenture and administered by a Bond Trustee. The Recovery Property as well as all other rights and assets of the SPE (Bond Collateral) will be pledged to the Bond Trustee for the benefit of the holders of the Wildfire Rate Relief Bonds and to secure payment of debt

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[5] The Wildfire Rate Relief Bonds may be issued in one or two series and through one or more SPE. All references to the SPE shall be applicable to all SPEs that are created to issue any particular series of Wildfire Rate Relief Bonds. The SPE may be either a newly created entity or the existing SPE created and utilized in connection with the Initial, Second, and Third AB 1054 Securitizations, whichever course is determined to be the most appropriate approach for the issuance of the Wildfire Rate Relief Bonds authorized pursuant to this application.

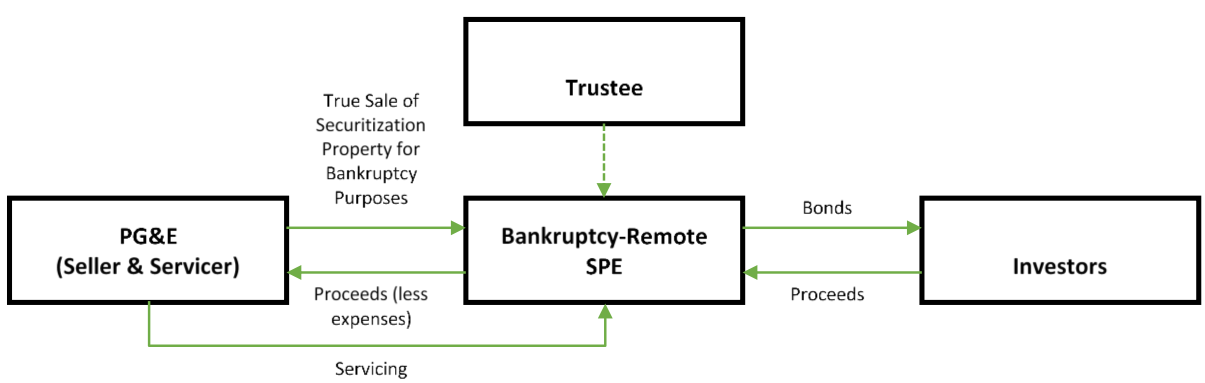
service on the Wildfire Rate Relief Bonds and all other Ongoing Financing Costs.[6]

PG&E will contribute equity to the SPE of not less than 0.50 percent of the initial aggregate principal amount of the Wildfire Rate Relief Bonds. The SPE equity will be pledged as Bond Collateral to secure the Wildfire Rate Relief Bonds and will be deposited into a capital subaccount (described below) held by the Bond Trustee. This equity contribution is a requirement of the Internal Revenue Service (IRS) in order to characterize the Wildfire Rate Relief Bonds as obligations of PG&E for federal income tax purposes.

To fund the acquisition of the Recovery Property, the SPE will issue Wildfire Rate Relief Bonds to investors. The Wildfire Rate Relief Bonds will be secured by the Bond Collateral held by the Bond Trustee. Holders of Wildfire Rate Relief Bonds secured by this Bond Collateral may exercise all remedies pursuant to this security interest if there is a default. The proceeds (net of Upfront Financing Costs) from the Wildfire Rate Relief Bonds will be transferred from the SPE to PG&E as payment of the purchase price for the Recovery Property.

The following diagram illustrates the Wildfire Rate Relief Bond transaction structure:

FIGURE 3-1
TRANSACTION STRUCTURE



The Bond Trustee will retain all WRRFRC collections received from PG&E in a collection account (Collection Account) and distribute these funds to make

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6 For the avoidance of doubt, the Bond Collateral is specific to each series of Wildfire Rate Relief Bonds. There is no cross-collateralization among different series of Wildfire Rate Relief bonds previously issued and that may be issued in the future.

scheduled principal and interest payments on the Wildfire Rate Relief Bonds and to pay Ongoing Financing Costs in accordance with the bond indenture "waterfall" provisions. PG&E anticipates that the collection account would include three subaccounts: (1) a general subaccount to hold revenues and investment earnings pending application under the indenture waterfall provisions (General Subaccount); (2) a capital subaccount to hold the equity capital contribution made by PG&E (Capital Subaccount); and (3) an excess funds subaccount to hold revenues and investment earnings collected in excess of amounts necessary to pay principal, interest and other Ongoing Financing Costs (Excess Funds Subaccount). The Collection Account may also contain additional accounts to accommodate any credit enhancements (including any overcollateralization subaccount) approved in an Issuance Advice Letter.

The Bond Trustee would invest all WRRFRC collections in investment grade short-term debt securities that mature on or before the next Wildfire Rate Relief Bond payment date. Any investment earnings would be retained in the Collection Account to pay principal, interest, or other Ongoing Financing Costs. If any funds remain in the collection account after distributions are made on a Wildfire Rate Relief Bond payment date, they would be credited to the Excess Funds Subaccount. These amounts in the Excess Funds Subaccount, as well as the Capital Subaccount, would be available to pay principal, interest, or Ongoing Financing Costs as they come due. Any excess moneys in the Excess Funds Subaccount would be used to offset and reduce the WRRFRC on the next WRRFRC adjustment date.

Upon payment in full of all Wildfire Rate Relief Bonds and the discharge of all Ongoing Financing Costs, amounts remaining with the Bond Trustee would be distributed in the following order of priority: first, an amount equal to PG&E's initial equity contribution into the capital subaccount, together with any authorized required rate of return (described below), would be paid to PG&E, and second, all other amounts held by the Bond Trustee in any fund or account (including any overcollateralization account) would be returned to PG&E, and such amounts, together with any WRRFRC revenues thereafter received by PG&E, would be credited to customers through normal ratemaking processes.

The Commission shall have full access to the books and records of the SPE. PG&E shall not make any profit from the SPE, provided that, as requested by

PG&E and as described herein and in the Form of Financing Order attached to the application and subject to approval of the Finance Team as described therein, PG&E shall receive an authorized rate of return on its equity contribution equal to the weighted average interest rate on the Wildfire Rate Relief Bonds. The equity contribution will be deposited in the Capital Subaccount. The return owed to PG&E will be payable as an Ongoing Financing Cost from WRRFRC revenues and will be distributed to PG&E on a semi-annual basis after payment of debt service on the Wildfire Rate Relief Bonds and all Ongoing Financing Costs.

The transaction structure described above is consistent with prior utility securitizations and is designed to ensure the highest possible rated Wildfire Rate Relief Bonds. Section E.1 below describes how the transaction structure addresses rating agency concerns.

1. Credit Rating Issues

The proposed transaction structure is necessary to ensure the highest possible rated Wildfire Rate Relief Bonds, thereby reducing interest costs for the benefit of customers. The credit rating agency reports on the Initial AB 1054 Securitization and Second AB 1054 Securitization, for example, considered and reflected the significance of the factors outlined below in supporting the strong, AAA credit rating for those bonds.[7]

Unambiguous support in regulatory approvals and legislative language would help ensure that the Wildfire Rate Relief Bonds receive the highest possible rating from nationally recognized credit rating agencies. The credit analysis conducted by the rating agencies of the Wildfire Rate Relief Bonds centers on the extent to which the structure of the transaction isolates the securitized assets (Recovery Property) from the credit risks of the originating company (PG&E), and on the credit quality of those assets themselves. The credit ratings would be based on several factors, including those listed in

[7] The agencies emphasized the strength of California's securitization law and the irrevocable Commission financing order and recovery property, the uncapped True-Up mechanism, and the capital subaccount fully funded in the amount of 0.50 percent of the initial principal balance of the bonds. See, for example, Moody's Rating Action regarding the PG&E Recovery Funding LLC recovery bonds, dated October 26, 2021, Moody's Rating Action regarding the PG&E Recovery Funding LLC recovery bonds, dated November 30, 2022.

Chapter 2, Background on Utility Securitization (K. Niehaus), and those described below.

a. Bankruptcy Opinions

In connection with the transaction, PG&E would provide to the credit rating agencies an opinion from its legal counsel that: (1) the transfer of the Recovery Property from PG&E to the SPE constitutes a "true sale" for bankruptcy purposes; and (2) such SPE would not be substantively consolidated with PG&E for bankruptcy purposes. This legal opinion would provide assurance to the credit rating agencies that the SPE's assets (including Recovery Property) would not be part of PG&E's bankruptcy estate, and thus not be available to PG&E's creditors, should PG&E subsequently commence bankruptcy proceedings. Instead, this revenue stream would continue to be collected for the SPE, which has pledged it to investors to pay Wildfire Rate Relief Bond debt service and other costs.

The Wildfire Rate Relief Bond transaction structure would include the features required by counsel to deliver the required "bankruptcy remote" opinions, including: (1) restrictions in the SPE organizational documents limiting the activities of the SPE to the issuance of Wildfire Rate Relief Bonds and related activities and eliminating the SPE's ability to voluntarily file for bankruptcy; (2) the appointment of one or more independent directors to the SPE board; (3) the payment of servicing and administration fees adequate to compensate PG&E; and (4) adequate notice to customers and creditors of PG&E of the SPE's ownership of the Recovery Property. These structural characteristics, among others, should permit the delivery of the true sale and non-consolidation opinions by legal counsel required by the rating agencies.

b. WRRFRC Characteristics

Article 5.8 provides that the WRRFRCs would be both irrevocable and non-bypassable (as further discussed in Chapter 7, Rate Proposal (B. Kolnowski)), which assures Wildfire Rate Relief Bond investors that the WRRFRCs would not be interrupted, eliminated, or avoided by consumers in PG&E's Service Territory. Except for specified exemptions in Section 850.1(i), the WRRFRCs would be applicable to all existing and future electric consumers in PG&E's Service Territory.

As further discussed in Chapter 7, Rate Proposal (B. Kolnowski), and consistent with the revenue allocation settlement agreement adopted by the Commission in the 2020 GRC Phase II proceeding (Revenue Allocation (RA) Settlement Agreement),[8] the WRRFRCs would be imposed on all nonexempted customers based on the allocation methodology set forth in the RA Settlement Agreement. Under this approach, a special allocator as described in the RA Settlement Agreement (Special Allocator) will be calculated at issuance of the Wildfire Rate Relief Bonds pursuant to the formula set forth in the RA Settlement Agreement, and changes to the initial allocation factors will be limited to adjustments for changes in sales as necessary to collect the revenue requirement. This is consistent with the allocation adopted in prior securitizations under AB 1054.[9]

In addition to the Authorized Amount, PG&E must be able to recover, through the WRRFRCs, the Ongoing Financing Costs associated with servicing the Wildfire Rate Relief Bonds and supporting the operations of the SPE. These Ongoing Financing Costs include, without limitation, servicing fees, administration fees, legal fees and expenses, accounting fees and expenses, rating agency surveillance fees, trustee fees and expenses, independent director fees, printing/EDGARizing expenses, return on equity, miscellaneous fees and expenses, and credit enhancement costs, if required, in order to ensure the bankruptcy remoteness of the SPE and obtain the highest possible rating on the Wildfire Rate Relief Bonds.

c. True-Up Mechanism

The statutorily authorized "True-Up" mechanism, which is common to all utility securitizations, including those in California, is the critical

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8 See D.21-11-016 at 87-90 (Section 6.6.4, "Allocation of Wildfire Mitigation Costs"); see also *id.* at 169 (OP 15, "Pacific Gas and Electric Company shall implement the provisions of the revenue allocation settlement as soon as practicable").

9 See D.21-06-030 at 81; D.22-08-004 at 77-78; D.24-02-011 at 78-80.

credit enhancement feature for securitization bonds. This mechanism requires the periodic adjustment of the WRRFRCs so that the WRRFRC revenues are sufficient to pay, on a timely basis, the Wildfire Rate Relief Bonds, and all Ongoing Financing Costs (including the replenishment of any draws on the Capital Subaccount) related to such series of Wildfire Rate Relief Bonds. Article 5.8 requires the Commission to adjust the WRRFRCs at least annually, and more often, if necessary, to ensure the WRRFRC revenues are sufficient to timely pay the Wildfire Rate Relief Bonds and all Ongoing Financing Costs related to such series of Wildfire Rate Relief Bonds. To satisfy this statutory requirement for a periodic True-Up adjustment of the WRRFRCs, PG&E proposes that the WRRFRC be adjusted: (1) annually (and quarterly beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of a series of Wildfire Rate Relief Bonds) to correct any overcollection or undercollection of WRRFRC revenues; and (2) semi-annually or more frequently, if necessary, to ensure that the WRRFRCs generate sufficient revenues to make timely payments of all scheduled (or legally due) payments of principal (including, if any, prior scheduled but unpaid principal payments), interest and other Ongoing Financing Costs for each of the two payment periods (generally six months) following the effective date of the initial or adjusted WRRFRC. PG&E requests that the Commission approve the use of an Advice Letter process to implement the periodic True-Ups, consistent with the process adopted by the Commission in prior PG&E securitizations under AB 1054.

Under PG&E's proposal, PG&E would submit annual (and, beginning 12 months prior to the last scheduled final payment date of the last maturing tranche of a series of Wildfire Rate Relief Bonds, at least quarterly), semi-annual and interim Routine True-Up Mechanism Advice Letters until the Wildfire Rate Relief Bonds and all Ongoing Financing Costs are paid in full.

TABLE 3-1
SUMMARY OF TRUE-UP ADVICE LETTERS

Line No.	Advice Letter Type	Tier	Timing	Description
1	Annual Routine True-Up Advice Letter	1	50 days before the annual adjustment date set forth in the Issuance Advice Letter.	Annual adjustment to the WRRFRC.
2	Semi-Annual Routine True-Up Advice Letter	1	If necessary, 50 days before the semi-annual adjustment date, which should be six months after the annual adjustment date set forth in the Issuance Advice Letter.	WRRFRC Adjustment if PG&E forecasts that collections will be insufficient to make scheduled payments of Wildfire Rate Relief Bond principal, interest, and other Ongoing Financing Costs.
3	Interim Routine True-Up Advice Letter	1	If necessary, 50 days before proposed effective date with effective date at the beginning of a month.	WRRFRC Adjustment if forecasted collections would be insufficient to make all scheduled payments on a timely basis during the current or next succeeding payment period.
4	Non-Routine True-Up Advice Letter	2	90 days before proposed effective date.	WRRFRC Adjustments to reflect revisions to the logic, structure and components of the Cash Flow Model described in Attachment1 of the Form of Financing Order.

- Annual Routine True-Up Mechanism Advice Letters

  PG&E shall submit annual Routine True-Up Mechanism Advice Letters with a complete accounting of the historical over-collection and under-collection of the WRRFRC at least 50 days before the annual adjustment date specified in the Issuance Advice Letter (WRRFRC Annual Adjustment Date) until the Wildfire Rate Relief Bonds and all other Ongoing Financing Costs have been paid in full using the WRRFRC Consumer Class allocations based on the RA Settlement Agreement, adjusted for changes in sales as necessary to collect the WRRFRC revenue requirement. These submissions are meant to ensure that the actual WRRFRC collections are neither more nor less than required to repay the Wildfire Rate Relief Bond principal, interest and all other Ongoing Financing Costs related to such series of Wildfire Rate Relief Bonds. Because the revised WRRFRC in the annual Routine True-Up Mechanism Advice Letters should be ministerial, they may be Tier 1 Advice Letters, and are to receive a Commission negative or affirmative response within 20 days of submission so as to enable PG&E's timely revisions to the WRRFRC to go into effect on the applicable WRRFRC Annual Adjustment Date.

- Semi-Annual Routine True-Up Mechanism Advice Letters

  PG&E should also submit, if it is required, semi-annual Routine True-Up Mechanism Advice Letters with a complete accounting of the historical over-collection and under-collection of the WRRFRC. The semi-annual True-Up adjustments shall be used if PG&E forecasts that WRRFRC collections will be insufficient to make scheduled payments of Wildfire Rate Relief Bond principal, interest, and other Ongoing Financing Costs on a timely basis during the current or next succeeding payment period or to replenish any draws upon the capital subaccount. If PG&E determines a semi-annual True-Up is required, PG&E shall submit a semi-annual Routine True-Up Advice Letter (as described in the Form of Financing Order) at least 50 days before the semi-annual adjustment date which shall be six months after the WRRFRC Annual Adjustment Date. The revisions to the WRRFRC in the semi-annual Routine True-Up Mechanism Advice Letters should be ministerial, the semi-annual Routine True-Up Mechanism Advice Letters may be Tier 1 Advice Letters, and the semi-annual Routine True-Up Mechanism Advice Letters are to receive a Commission negative or affirmative response within 20 days of submission so as to enable PG&E's timely revisions of the WRRFRC to go into effect on the applicable WRRFRC semi-annual adjustment date.

- Interim Routine True-Up Mechanism Advice Letters

  PG&E may also submit interim Routine True-Up Mechanism Advice Letters at such other times as PG&E deems necessary. The interim True-Up adjustment would be used if PG&E forecasts that WRRFRC collections would be insufficient to make all scheduled payments of principal and interest on the Wildfire Rate Relief Bonds and other Ongoing Financing Costs (including the replenishment of any draws on the capital subaccount) on a timely basis during the current or next succeeding payment period. If PG&E determines that an interim Routine True-Up Advice Letter is necessary, PG&E would submit an interim Routine True-Up Advice Letter at least 50 days before the proposed effective date of the revised WRRFRC (which, for efficacy of reporting, will be the first day of a month). These may be Tier 1 Advice Letters, and they are to receive a Commission negative or affirmative response within 20 days of submission so as to enable PG&E's timely revisions of the WRRFRC. All Routine True-Up Mechanism Advice Letters would be based on the pro forma example in Attachment 3 to the Form of Financing Order.

Prompt implementation of the Routine True-Up Mechanism Advice Letters is critical to the rating agencies' determination of: (1) the reliability and adequacy of funds to make debt service payments on the Wildfire Rate Relief Bonds; and (2) whether other credit enhancements would be required to obtain the highest possible credit ratings. Since it is important that the Wildfire Rate Relief Bonds have the highest possible credit rating, and because the Routine True-Up Mechanism Advice Letters should be ministerial, the WRRFRC adjustments proposed in Routine True-Up Mechanism Advice Letters would be implemented as described previously. Parties would have limited notice and opportunity to protest the Routine True-Up Mechanism Advice Letters, and the Energy Division would review the Routine True-Up Mechanism Advice Letters, but only to confirm the mathematical accuracy of the proposed True-Up adjustment. Therefore, even though PG&E proposes that the Commission establish a mechanism to implement revisions to the WRRFRCs automatically, all WRRFRC-related Routine True-Up Mechanism Advice Letters would be subject to protest, review, and correction to the fullest extent allowed by Section 850.1(e). However, any protest, review, and correction would be limited to the correction of mathematical errors in the Routine True-Up Mechanism Advice Letter. No protest, review or required modification to correct an error in a Routine True-Up Mechanism Advice Letter would delay its effective date, and any correction or modification which could not be made prior to the effective date would be made in the next true-up.

- Non-Routine True-Up Mechanism Advice Letters

  Non-Routine True-Up (as described in the Form of Financing Order) to reflect revisions to the logic, structure and components of the Cash Flow Model described in Attachment 1 of the Form of Financing Order or as adjusted in a subsequent Non-Routine True-Up Mechanism Advice Letter would be submitted at least 90 days before the date when the proposed changes would become effective, with the resulting changes effective on the effective date identified in the Non-Routine True-Up Mechanism Advice Letter. PG&E proposes that the Energy Division prepare for the Commission's consideration a resolution that adopts, modifies, or rejects the proposed revisions to the cash flow model as proposed in the Non-Routine True-Up Mechanism Advice Letter. The public would have an opportunity to review and protest a Non-Routine True-Up Mechanism Advice Letter in accordance with Commission procedures to the fullest extent allowed by Section 850.1(e). Absent a Commission resolution that adopts, modifies, or rejects the Non-Routine True-Up Mechanism Advice Letter, PG&E may implement WRRFRC adjustments proposed in a Non-Routine True-Up Mechanism Advice Letter on the effective date identified in the letter.

  The Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters shall calculate a revised WRRFRC for each series of Wildfire Rate Relief Bonds using the allocations based on the RA Settlement Agreement, and Cash Flow Model specified in Attachment 1 of the Form of Financing Order or as subsequently modified in a Non-Routine True-Up Mechanism Advice Letter, as applicable, except that:

- The Periodic Payment Requirement would be (1) increased or decreased by the amount by which actual remittances of WRRFRC revenues to the Bond Trustee collection account through the end of the month preceding the month of calculation was less than or exceeded the Periodic Payment Requirement for the prior period, and (2) to the extent not included in (1), decreased by the amount projected to be held in the excess funds subaccount at the beginning of the next payment period.
- Forecasted sales for the remainder of the current year and for the subsequent year, if applicable, of the transaction would be revised to reflect PG&E's latest estimate of sales.
- Estimated Ongoing Financing Costs will be modified to reflect changed circumstances.
- Assumed uncollectibles will be modified to equal the percentage of losses actually experienced during the most recent 12-month billing period for which such information is available. An adjustment will be made to reflect collections that will be received at the existing tariff rate from the end of the month preceding the date of the calculation through the end of the month in which the calculation is done.

All true-up adjustments to the WRRFRCs would ensure the billing of WRRFRCs necessary to correct for any over-collection or under-collection of the WRRFRCs and to generate sufficient revenues to make timely payments of all scheduled (or legally due) payments of principal (including, if any, prior scheduled but unpaid principal payments), interest and other Ongoing Financing Costs for each of the two payment periods (generally six months) following the effective date of the initial or adjusted WRRFRC. Such amounts are referred to as the "Periodic Payment Requirement." True-Up submissions would be based upon the cumulative differences, regardless of the reason, between the Periodic Payment Requirement and the actual amount of WRRFRC collections remitted to the Bond Trustee for the series of Wildfire Rate Relief Bonds.

PG&E has requested that the Commission find in the Form of Financing Order that the Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters described above constitute "applications" within the meaning of Section 850.1(g) and authorize PG&E to submit these Advice Letters to implement true-up adjustments to the WRRFRCs.

d. Credit Enhancement, Capital Subaccount and Return

The SPE may obtain additional credit enhancements to ensure repayment of the Wildfire Rate Relief Bonds in the form of an overcollateralization subaccount if the credit rating agencies require overcollateralization to receive the highest possible credit rating on the Wildfire Rate Relief Bonds, or if the all-in cost of the Wildfire Rate Relief Bonds with the overcollateralization would be less than without the overcollateralization. Overcollateralization is a credit enhancement technique in which amounts collectible in relation to a financial asset exceed the required payments on security, ensuring investors timely payment. The required amount of overcollateralization, if any, would be collected as an Ongoing Financing Cost payable via the WRRFRCs. The overcollateralization requirement, if any, would be sized based upon input from the rating agencies indicating the amount necessary to achieve the highest possible credit rating. Any overcollateralization that is collected from customers in excess of total debt service and other Ongoing Financing Costs would be the property of the SPE.

The SPE may also obtain bond insurance, letters of credit, and similar credit enhancing instruments, but only if required by the credit rating agencies to achieve the highest possible credit rating on the Wildfire Rate Relief Bonds, or if the all-in cost of the Wildfire Rate Relief Bonds with these other credit enhancements would be less than without the enhancements.

PG&E does not anticipate requiring any external credit enhancements described in the preceding paragraph for the issuance of

Wildfire Rate Relief Bonds.[10] Further, based upon current market conditions, PG&E does not anticipate being required by the rating agencies to establish an overcollateralization subaccount for the issuance of Wildfire Rate Relief Bonds, but to the extent such an account is required, the exact amount and timing of its collection via the WRRFRCs would be determined before the Wildfire Rate Relief Bonds are issued and approved through the Issuance Advice Letter process. Consistent with its prior securitizations under AB 1054, PG&E requests this flexibility in the Form of Financing Order to provide such credit enhancement should market conditions change.[11]

In addition, the bond collateral held by the Bond Trustee would be available as a credit enhancement. This collateral would include, as mentioned above, an equity contribution in an amount required to obtain favorable IRS tax treatment for the transaction, as described below in Section 8, Tax Issues (i.e., currently 0.50 percent of the initial aggregate principal amount of the Wildfire Rate Relief Bonds issued). If the equity capital is drawn upon, it may be replenished from future WRRFRCs. PG&E has requested that it be entitled to receive an authorized rate of return on its equity contribution equal to the weighted average interest rate on the Wildfire Rate Relief Bonds authorized pursuant to this application. This equity return would be paid as an Ongoing Financing Cost from the WRRFRC revenues and would be distributed to PG&E on a semi-annual basis, after payment of debt service on the Wildfire Rate Relief Bonds and other Ongoing Financing Costs.

e. WRRFRC Revenue Forecasts

In addition to evaluating the effectiveness of the WRRFRC true-up mechanism, the rating agencies would also analyze PG&E’s ability to

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[10] PG&E notes that such credit enhancements were not required for the Initial AB 1054 Securitization, the Second AB 1054 Securitization, and the Third AB 1054 Securitization.

[11] D.21-06-030 at 121 (OP 17); D.22-08-004 at 116 (OP 17); D.24-02-011 at 119 (OP 17) (finding that the SPE “may obtain credit enhancement in the form of an over-collateralization . . . but only if: (i) the credit enhancements are required by the rating agencies, or (ii) the all-in cost of the Recovery Bonds with the credit enhancements is expected to be less than without the credit enhancements”).

make accurate forecasts of energy usage by its community choice aggregation, community aggregation, bundled and direct access electric customers, by looking at historical data on a forecasted versus actual usage basis. The rating agencies are expected to apply a wide range of assumptions on uncollectibles, average days to customer payment (or "average days sales outstanding"), and energy usage as well as the effectiveness of the true-up mechanism to assess the sensitivity of WRRFRC revenues to changes in those assumptions.

f. Billing by Third Parties

The rating agencies would also focus on the financial strength and the billing and collecting experience of the servicer. Although not common, third parties bill and collect payments from some of the customers that would pay the WRRFRC. In order to ensure that the Wildfire Rate Relief Bond credit rating would not be adversely affected, PG&E requests that the Commission continue to require that the following principles be applied in establishing minimum standards for all Electric Service Providers or other third parties (Third-Party Billers) that bill and collect the WRRFRCs from electric customers.

- Regardless of who would be responsible for performing the billing and collection functions, electric customers would continue to be responsible for paying the WRRFRCs. Electric customers must always be responsible for paying the WRRFRCs, regardless of who actually bills and collects that charge from those customers. This clear and continuing customer obligation is unaffected by Third-Party Billers billing and collecting the WRRFRC and then paying their aggregated WRRFRC collections to PG&E.
- Even if a Third-Party Biller performs the metering and billing functions for the WRRFRCs, PG&E must have access to information regarding customer usage and billings in order to properly report WRRFRC revenues to the Bond Trustee as required under its Servicing Agreement.
- Since appropriate shut-off policies must be maintained to minimize investors' credit risk in the case of non-payment of the WRRFRCs by Third-Party Billers or specific customers, current shut-off policies

must be maintained to allow action by PG&E in the case of non-payment of the WRRFRCs, regardless of who is responsible for billing and collecting the WRRFRCs; provided, however, that temporary changes in utility shut-off procedures due to emergencies will be permitted.

- Appropriate standards, procedures, and credit policies must be in place to ensure that the collection of WRRFRCs by a Third-Party Biller does not result in an increased risk to Wildfire Rate Relief Bond investors. Such standards should be consistent with existing rating agency standards governing billing, collecting, and reporting for servicers in similar utility securitization transactions. Rating agencies and potential Wildfire Rate Relief Bond investors would see an additional layer of risk if Third-Party Billers with less than investment grade credit ratings collect and hold WRRFRCs prior to remittance to PG&E. To ensure that the risk associated with Third-Party Biller default is mitigated, rating agencies would want to see that appropriate credit policies are in place. For example, if a Third-Party Biller conducting metering and billing were not rated or were rated below investment grade, the rating agencies might require that all customer collections be remitted daily or, alternatively, might require security deposits, letters of credit, or other forms of credit enhancement from PG&E. Furthermore, a Third-Party Biller conducting metering and billing must have systems capabilities and procedures in place that are necessary to bill, collect, and report, and as applicable, pay the WRRFRCs over to PG&E.
- In the event of default by a Third-Party Biller conducting metering and billing, billing and collecting responsibilities must be promptly transferred to another party to minimize potential losses of WRRFRC revenues. If a Third-Party Biller defaults on its timely payments to PG&E of WRRFRC collections, the rating agencies would expect prompt action to replace the defaulting entity to assure that the WRRFRCs paid by consumers could be passed on to Wildfire Rate Relief Bond investors. PG&E’s current electric rules

meet this requirement by requiring that defaulting Third-Party Billers be replaced by PG&E for metering and billing within two months.

Maintaining these guidelines is important to achieving the highest possible credit rating and the minimum ratepayer cost associated with the Wildfire Rate Relief Bond issuance. As a result, PG&E requests that the Commission continue to require that PG&E maintain appropriate procedures for Third-Party Billers conducting metering and billing as set forth in PG&E's Electric Rule 22.P., "Credit Requirements."

g. Legislative and Regulatory Risks; Risk of Municipalization

Additional factors the rating agencies would consider when rating the Wildfire Rate Relief Bonds are the legislative risks associated with Article 5.8, including the risk that the authorizations or requirements therein could be overturned or abolished in the future by any means, including voter initiatives. Since the amendments to Article 5.8 in AB 1054 were passed by very high margins in the California Legislature, PG&E expects the rating agencies to conclude, as it did for example in the Initial AB 1054 Securitization and the Second AB 1054 Securitization,[12] that the legislative risk associated with the transaction should not affect the Wildfire Rate Relief Bond credit ratings. Furthermore, the support of key customer constituencies in both the legislative and regulatory process should also reassure the rating agencies that the voter initiative risk should not affect the Wildfire Rate Relief Bond ratings.

The rating agencies would also analyze the regulatory risk associated with the transaction. As stated in Article 5.8, the Commission's financing orders and the WRRFRCs would be irrevocable. The Commission would not have authority either by rescinding, altering, or amending the financing order or otherwise, to revalue or revise for ratemaking purposes the recovery costs or the costs of recovering, financing, or refinancing the recovery costs, or in any way to reduce or impair the value of Recovery Property either

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12 See footnote 7.

directly or indirectly by taking WRRFRCs into account when setting other rates.

In the event of a future municipalization or an acquisition of PG&E's facilities by an entity that does not set retail rates subject to the Commission's regulation, the Commission would ensure continued payment of WRRFRCs by placing conditions on the Commission's approval of the transaction.[13] By conditioning its approval on the continued payment of WRRFRCs, the Commission's approach would respect the State's legal obligation under AB 1054 not to limit or alter the WRRFRCs until the Wildfire Rate Relief Bonds and all related Ongoing Financing Costs are fully paid.[14]

Nevertheless, the quality of the financing order, particularly with regard to the initial tariff implementation, the true-up mechanism and requirements for Third-Party Billers, including potentially municipal acquirers, would be carefully reviewed by the rating agencies when they determine the rating of the Wildfire Rate Relief Bonds.

2. Tax and Accounting Issues

a. Tax Issues

The transaction would be structured to be a "Qualifying Securitization," pursuant to IRS Revenue Procedure 2005-62, as modified by IRS Revenue Procedure 2024-15, such that: (1) the SPE will be a wholly owned subsidiary of PG&E capitalized with an equity interest of at least 0.50 percent of the initial aggregate principal amount of Wildfire Rate Relief Bonds issued; (2) the Wildfire Rate Relief Bonds

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[13] See SB 550 (2019); Pub. Util. Code §§ 851(a), (b)(1), 854.2(b)(1)(F). Taken together, those provision require the Commission's authorization for any sale or disposition of the utility's system or property (via a transaction greater than $5 million), including for any "voluntary or involuntary change in ownership of assets from an electrical or gas corporation to ownership by a public entity."

[14] See Pub. Util. Code § 850.1(e) ("The State of California does hereby pledge and agree with the electrical corporation, owners of recovery property, financing entities, and holders of recovery bonds that the state shall neither limit nor alter, except as otherwise provided with respect to the true-up adjustment of the fixed recovery charges pursuant to subdivision (i), the fixed recovery charges, any associated FRTA, recovery property, financing orders, or any rights under a financing order until the recovery bonds, together with the interest on the recovery bonds and associated financing costs, are fully paid and discharged …").

will be secured by the Recovery Property; (3) the WRRFRCs will be non-bypassable and payable by consumers within PG&E's Service Territory; and (4) payments on the Wildfire Rate Relief Bonds will be on a semi-annual basis. As a "Qualifying Securitization," the establishment of the Recovery Property, the transfer of Recovery Property to the SPE, and the issuance of Wildfire Rate Relief Bonds will not cause current recognition of gross income to PG&E for federal income tax purposes. The transfer would not be treated as a sale for tax purposes, and the Wildfire Rate Relief Bonds will be treated as PG&E's own debt for tax purposes. PG&E would secure an opinion of tax counsel to the effect that the Wildfire Rate Relief Bond transaction is a "Qualifying Securitization" under IRS Revenue Procedure 2005-62, as modified by IRS Revenue Procedure 2024-15.

Chapter 5, Taxation (T. Wedlake) describes the tax consequences of the Wildfire Rate Relief Bonds.

b. Accounting Issues

The Wildfire Rate Relief Bonds would be recorded as debt on PG&E's consolidated balance sheet. This is either positive or neutral to rating agency calculations of debt depending on whether the rating agency considers the Wildfire Rate Relief Bond debt as on or off balance sheet for credit purposes, as further discussed in Chapter 2, Background on Utility Securitization (K. Niehaus). PG&E will include a note to its financial statements disclosing that the Wildfire Rate Relief Bonds are secured solely by Recovery Property and related collateral subaccounts (including the SPE equity); that Wildfire Rate Relief Bond investors have no recourse to any assets or revenues of PG&E; that while such SPE is a subsidiary of PG&E, it is legally separate from PG&E; that the assets of such SPE are not available to creditors of PG&E; and that the Recovery Property is not legally an asset of PG&E.

F. Servicing the Wildfire Rate Relief Bonds

PG&E intends to act as servicer for the Recovery Property that would be pledged to secure the Wildfire Rate Relief Bonds, as reflected in a Servicing Agreement between PG&E and the SPE. The role of the servicer in utility securitizations is generally described in Chapter 2, Background on Utility Securitization (K. Niehaus). In its capacity as servicer, PG&E would be responsible for determining consumers' electricity usage, billing, collecting, and remitting the WRRFRCs to the Bond Trustee, and submitting Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters as described above. To the extent PG&E's consumers of electricity are billed by Third-Party Billers, PG&E proposes to bill these Third-Party Billers for the WRRFRCs, with the Third-Party Billers being obligated to remit WRRFRC collections to PG&E. PG&E would remit estimated WRRFRC collections to date, on behalf of the SPE, to the Bond Trustee, as described in Section I below. The Bond Trustee would be responsible for making principal and interest payments to Wildfire Rate Relief Bond investors and paying Ongoing Financing Costs.

The SPE would be required to pay PG&E a servicing fee that constitutes fair and adequate consideration sufficient to obtain the true sale and bankruptcy opinions. The Bond Trustee would pay this servicing fee to PG&E as servicer from WRRFRC collections. PG&E expects to charge an annual servicing fee of 0.05 percent of the initial principal amount of the Wildfire Rate Relief Bonds, plus out-of-pocket expenses (e.g., legal, accounting fees), to cover PG&E's incremental costs and expenses in servicing the Wildfire Rate Relief Bonds. As described in Chapter 6, Ratemaking Mechanisms (S. Sims), servicing fees in excess of PG&E's incremental costs will be credited to customers through the WHFRCBA. In the event that PG&E is unable to perform its servicing functions satisfactorily, as set forth in the Servicing Agreement, or is required to discontinue its billing and collecting functions, an alternate servicer acceptable to the Bond Trustee, acting on behalf of the Wildfire Rate Relief Bond holders and approved by the Commission, would replace PG&E and assume such billing and collecting functions. In the event PG&E is replaced and the new servicer must bill only the WRRFRC instead of the entire customer bill, servicing fees would be up to 0.60 percent of the initial principal amount of the Wildfire Rate Relief Bonds in order to ensure that a new servicer can be retained, subject to approval by the Finance Team in the Issuance Advice Letter, consistent with prior securitizations under AB 1054.[15] As discussed above and in Chapter 2, Background on Utility Securitization (K. Niehaus), the credit quality, and expertise in performing servicing functions are important considerations when appointing an alternate servicer to ensure the Wildfire Rate Relief Bond credit ratings are maintained. Chapter 2, Background on Utility Securitization (K. Niehaus) provides support for the servicing fees for PG&E and any replacement servicer. Moreover, PG&E believes that the remedy of allowing the Commission to sequester WRRFRCs in the cases of certain events of default under the Servicing Agreement upon the application of the Bond Trustee, as permitted by Section 850.3(e), will enhance the credit quality of the Wildfire Rate Relief Bonds.

If PG&E no longer performs servicing functions, the servicing fee would be paid directly to the successor servicer by the Bond Trustee. PG&E would not resign as servicer without prior Commission approval.

G. Administrator of the SPE

As described above, the Wildfire Rate Relief Bonds would be issued by a "bankruptcy -remote" SPE.[16] The SPE would have no employees. As a consequence, PG&E must provide administrative services to the SPE for the SPE to function as an independent legal entity. These administrative services may include, among others, maintaining general accounting records, preparation of quarterly and annual financial statements, arranging for annual audits of the SPE's financial statements, preparing all required external financial filings, preparing any required income or other tax returns, and related support. These services are separate from those of the servicer.

To compensate PG&E for its administrative services and thus ensure the "bankruptcy remote" status of the SPE as discussed above, PG&E would be paid an annual administration fee plus out-of-pocket expenses (e.g., legal, accounting fees), combined estimate to total $75,000 per year. This compensation is meant to cover expenses associated with administrative

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15 See Advice Letter (AL) 6390-E, dated November 5, 2021 and AL 6769-E, dated November 21, 2022.

16 The SPE may be either a newly created entity or the existing SPE created in connection with the Initial AB 1054 Securitization, whichever course is determined to be the most appropriate approach for the issuance of the Wildfire Rate Relief Bonds.

services provided by PG&E. Chapter 2, Background on Utility Securitization (K. Niehaus), provides support for the administration fee. Nevertheless, as described in Chapter 6, Ratemaking Mechanisms (S. Sims), the portion of the administration fee that exceeds PG&E's incremental costs will be credited to customers through the WHFRCBA.

H. Ongoing Financing Costs

In addition to principle and interest on the Wildfire Rate Relief Bonds, consumers would pay, through the WRRFRCs, the Ongoing Financing Costs associated with servicing the Wildfire Rate Relief Bonds and supporting the operations of the SPE. These Ongoing Financing Costs include the amounts payable to PG&E as servicer or any successor servicer (as discussed above), the amounts payable to PG&E as administrator (as discussed above), trustee fees and expenses, independent director fees, legal fees and expenses, accounting fees, rating agency surveillance fees, a return on PG&E's equity contribution, or invested capital, deposited in the capital subaccount as well as any amounts required to replenish the capital subaccount if there has been a draw from such account, and miscellaneous other costs and expenses associated with servicing of the Wildfire Rate Relief Bonds. Ongoing Financing Costs also include any payments for any credit enhancement, including payments to Third-Party credit support providers (e.g., letters of credit or bond insurance providers), and any amount required to fund or replenish any reserve or overcollateralization relating to the Wildfire Rate Relief Bonds. Based upon current market conditions and the advice of its structuring advisor, PG&E does not anticipate that any such credit enhancement would be required for any issuance of Wildfire Rate Relief Bonds, but PG&E requests the flexibility to utilize credit enhancement should market conditions change and the use of credit enhancement would result in lower charges to consumers. Any such credit enhancement would be subject to approval through the Issuance Advice Letter process (described below).

Certain of these Ongoing Financing Costs, such as the administration fees and the amount of the servicing fee for PG&E (as the initial servicer) would be determinable, either by reference to an established dollar amount or a percentage, on or before any issuance of any series of Wildfire Rate Relief Bonds. PG&E's return on its equity contribution, or invested capital, would be the weighted average interest rate on each series of Wildfire Rate Relief Bonds. Ongoing Financing Costs would vary over the term of the Wildfire Rate Relief Bonds. Ongoing Financing Costs would be recoverable from the WRRFRCs, regardless of their amounts.

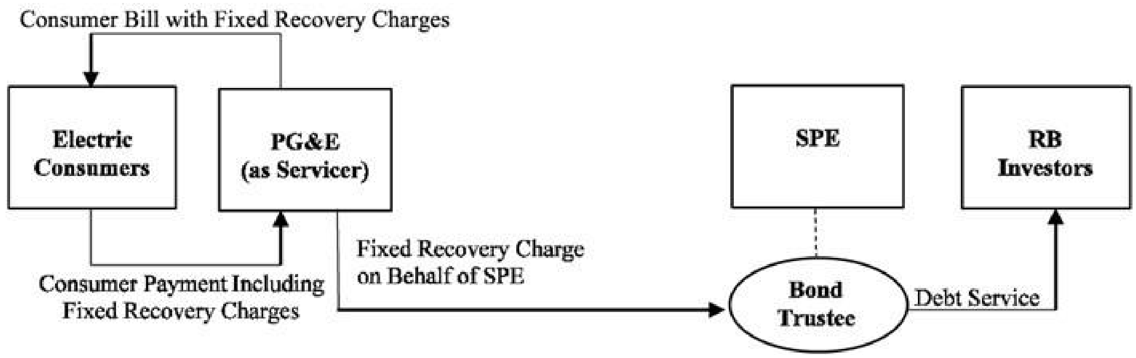
PG&E has estimated Ongoing Financing Costs (assuming PG&E will be the servicer, and that no overcollateralization or other credit enhancement is required) to be approximately $2.6 million on an annualized basis. These estimates are shown in Chapter 3, Attachment B. Updated estimates for the first and second payment period on the Wildfire Rate Relief Bonds will be included in the Issuance Advice Letter.

I. Billing and Remittance of WRRFRCs: Application of Revenues by Bond Trustee

As contemplated by Article 5.8, PG&E will act as the initial servicer for the Recovery Property that will be pledged to secure the Wildfire Rate Relief Bonds. As servicer, PG&E would be responsible for determining Consumers' electricity usage, billing, collecting, and remitting the WRRFRC collections to the Bond Trustee, and submitting Routine True-Up Mechanism Advice Letters and Non-Routine True-Up Mechanism Advice Letters as described above. To the extent Consumers of electricity in PG&E's Service Territory are billed by Third-Party Billers (as described in Section E.1.f. herein) PG&E will bill these Third-Party Billers, as the case may be, for the WRRFRCs, and the Third-Party Billers, as the case may be, will be obligated to remit WRRFRC revenues to PG&E. As servicer, PG&E will remit estimated WRRFRC revenues, on behalf of the SPE, to the Bond Trustee.

As servicer, PG&E will remit estimated WRRFRC revenues, on behalf of the SPE, to the Bond Trustee. The Bond Trustee will be responsible for making principal and interest payments to Wildfire Rate Relief Bond investors and paying Ongoing Financing Costs. The following diagram illustrates servicing cash flows.

FIGURE 3-2
SERVICING CASH FLOWS



As servicer, PG&E will remit WRRFRC revenues in accordance with the Servicing Agreement to the Bond Trustee. An SPE will own legal title to, and all equitable interest in, the Recovery Property, including the WRRFRCs, and PG&E will be legally obligated to remit all WRRFRC revenues to the Bond Trustee. PG&E expects the rating agencies to require PG&E to remit the estimated WRRFRC revenues to the Bond Trustee on a daily basis to avoid an adverse impact on the Wildfire Rate Relief Bond credit ratings.

Over the life of the Wildfire Rate Relief Bonds, PG&E would prepare a monthly servicing report for the Bond Trustee that shows the estimated WRRFRC revenues by month.[17] Estimated WRRFRC collections will be based on historic Consumer payment patterns. Six months after each monthly billing period, PG&E will compare actual WRRFRC revenues using PG&E's updated 6-month collection curve to the estimated WRRFRC revenues that have been remitted to the Bond Trustee for that month during the intervening 6-month period. The difference between the estimated WRRFRC collections and the actual WRRFRC collection will be netted against the following month's remittance to the Bond Trustee. The 6-month lag between the first remittance of estimated WRRFRC revenues and the final determination of actual WRRFRC cash collections allows for the collection process to take its course and is

[17] For the avoidance of doubt, if the Wildfire Rate Relief Bonds are issued using the SPE formed in connection with the Initial AB 1054 Securitization and used in the Second AB 1054 Securitization and Third AB 1054 Securitization, PG&E will prepare a monthly servicing report for the Bond Trustee for each series of Wildfire Hardening Recovery Bonds and Wildfire Rate Relief Bonds outstanding.

consistent with PG&E's practice of waiting six months after the initial billing before writing off unpaid customer bills.

The Bond Trustee (acting on behalf of the SPE) would have a legal right to only the amount of actual WRRFRC cash collections. PG&E acknowledges that, although it is remitting WRRFRC charges based upon an estimated basis, amounts collected that represent partial customer payments will be allocated between the Bond Trustee and PG&E through a reconciliation based on the ratio of the portion of the billed amount allocated for the WRRFRC to the total billed amount. This allocation is an important bankruptcy consideration in determining the true sale nature of the transaction. In the event of any default by the servicer, the Bond Trustee (on behalf of the SPE) will be entitled to receive a reconciliation of estimated collections and remittances to the Bond Trustee (described above) and actual collections of the WRRFRCs, including an allocation of partial payments based upon this pro rata allocation methodology.

As discussed above in Section E.1.f, although PG&E will act as servicer, it is possible that Third-Party Billers will bill and collect the WRRFRCs and any FRTAs from some Consumers. To the extent PG&E's consumers of electricity are billed by Third-Party Billers, PG&E proposes to bill these Third-Party Billers for the WRRFRCs, with the Third-Party Billers being obligated to remit WRRFRC collections to PG&E. PG&E would remit estimated WRRFRC collections to date, on behalf of the applicable SPE, to the Bond Trustee. These Third-Party Billers should meet minimum billing and collection experience standards and creditworthiness criteria. Otherwise, the rating agencies might impose additional credit enhancement requirements or assign lower credit ratings to the Wildfire Rate Relief Bonds. Therefore, PG&E requests that Third-Party Billers that bill and collect the WRRFRCs and any FRTAs will have to satisfy the creditworthiness and other requirements applicable to Energy Service Providers that meter and bill electric Consumers, as set forth in PG&E's Electric Rule 22.P. "Credit Requirements."

J. Issuance Advice Letter Process

As described above, the final terms and structure of each issuance of the Wildfire Rate Relief Bonds, including (without limitation) the principal amount, interest rates, number of tranches and principal amortization, scheduled final payment dates and final legal maturity dates of each tranche, as well as the use of any credit enhancement, would be determined at or before the time each series of Wildfire Rate Relief Bonds is priced. The final terms and structure would be designed, with the advice of the underwriters and the Finance Team, with the objective of reducing, to the maximum extent possible, the total cost of borrowing and, as a consequence, the total cost to consumers.

PG&E proposes that the final terms and structure of the Wildfire Rate Relief Bonds, updated estimates of the Upfront Financing Costs and the Ongoing Financing Costs for the first two payment periods after any issuance, as well as the initial WRRFRCs, be set forth in an Issuance Advice Letter to be submitted with the Commission not later than one business day after pricing of the Wildfire Rate Relief Bonds. The Issuance Advice Letter would be in the form shown in Attachment 2 to the Form of Financing Order. The Commission has approved the use of an Issuance Advice Letter process in each of the recent financing orders issued pursuant to Sections 850 *et seq.*[18] PG&E proposes that the final terms and structure of the Wildfire Rate Relief Bonds, the recovery of Upfront Financing Costs and all Ongoing Financing Costs incurred over the life of the Wildfire Rate Relief Bonds, as well as the initial WRRFRC, automatically be approved and become effective at noon on the fourth business day after pricing unless before noon on the fourth business day after pricing the staff of the Commission rejects the Issuance Advice Letter.

K. Upfront Financing Costs and Use of Net Proceeds

Financing costs (as defined in Section 850(b)(4)) associated with each issuance and any credit enhancement of the Wildfire Rate Relief Bonds (i.e., Upfront Financing Costs) would be financed from the proceeds of the Wildfire Rate Relief Bonds. Such Upfront Financing Costs include underwriting fees and expenses, legal fees and expenses (including those associated with this financing application), rating agency fees, accounting fees and expenses, company’s advisory fee, Securities and Exchange Commission (SEC) registration fees, Section 1904 fees, printing and EDGARizing expenses, trustee/trustee counsel fees and expenses, original issue discount, Commission and Finance Team costs and expenses, and other miscellaneous costs

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[18] See D.24-02-011 at 118-19 (OP 14); D.23-02-023 at 111 (OP 14); D.22-08-004 at 115-16 (OP 14); D.21-06-030 at 120-21 (OP 14); D.21-05-015 at 103-04 (OP 17); D.20-11-007 at 118-19 (OP 14).

approved in the Financing Order. Upfront Financing Costs include reimbursement to PG&E for amounts advanced for payment of such costs. Upfront Financing Costs may also include the costs of credit enhancements, as described above, including the costs of funding any reserve or overcollateralization account or of purchasing a letter of credit or bond insurance policy.

PG&E estimates that the Upfront Financing Costs associated with the Wildfire Rate Relief Bonds to be authorized pursuant to this application, assuming no credit enhancement, would be approximately $15.4 million, as shown in Chapter 3, Attachment A. However, Upfront Financing Costs are subject to change, as the costs are dependent on the timing of issuance, market conditions at the time of issuance, and other events outside PG&E's control, such as possible litigation, incremental legal fees resulting from protracted resolution of issues, possible review by the Commission, delays in the SEC registration process, Commission costs and expenses, and rating agency fee changes and requirements. When the Wildfire Rate Relief Bonds are sized and priced, Upfront Financing Costs would be updated and included in the Issuance Advice Letter.

If the estimated Upfront Financing Costs included in the Issuance Advice Letter exceed actual Upfront Financing Costs, any excess would be credited to the excess funds subaccount and used to offset the revenue requirement in the next routine WRRFRC True-Up calculation. In the event that the actual Upfront Financing Costs exceed the estimated amount in the Issuance Advice Letter, the shortfall amount may be recovered in the next routine true-up adjustment for the WRRFRCs.

PG&E proposes to use the proceeds from the issuance of the Wildfire Rate Relief Bonds to pay or reimburse PG&E for Authorized VM Expenses and to pay the Upfront Financing Costs.

L. Conclusion

PG&E requests that the Commission approve the proposed transaction and transaction structure as described in this chapter.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT A

ESTIMATED UPFRONT FINANCING COSTS

ESTIMATED UPFRONT FINANCING COSTS

Line No.	Financing Cost Descriptions	Amounts
1	Underwriters' Fees and Expenses	$9,485,616
2	Legal Fees and Expenses	1,465,000
3	Rating Agency Fees	1,285,000
4	Accounting Fees and Expenses	125,000
5	Company's Advisory Fee	255,000
6	Servicer Set-up Costs	0
7	SEC Registration Fees	350,019
8	Section 1904 Fees	1,191,702
9	Printing/EDGARizing Expenses	150,000
10	Trustee/Trustee Counsel Fee and Expenses	44,500
11	Original Issue Discount	100,000
12	Commission's Costs and Expenses	745,000
13	Miscellaneous	207,163
14	**Total**	**$15,404,000**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT B

ESTIMATED ONGOING FINANCING COSTS

ESTIMATED ONGOING FINANCING COSTS

Line No.	Financing Cost Descriptions	Amounts
1	Servicing Fee (PG&E as Servicer) ([0.05]% of the initial Recovery Bond principal amount)	$1,567,762
2	Administration Fee	99,167
3	Accounting Fees and Expenses	31,250
4	Legal Fees and Expenses	35,000
5	Rating Agency Surveillance Fees	45,000
6	Trustee Fees and Expenses	15,450
7	Independent Director Fees	3,000
8	Printing/EDGARizing Expenses	5,000
9	Return on Equity	835,774
10	Miscellaneous Fees and Expenses	10,000
11	Total Ongoing Financing Costs (with PG&E as Servicer)	$2,647,402
12	Ongoing Servicers Fee (Third Party as Servicer) ([0.60%]% of initial principal amount)	18,813,138
13	Total Ongoing Financing Costs (Third Party as Servicer)	$19,892,779

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT C

SECURITIZATION FIXED RECOVERY CHARGE AND

FIXED RECOVERY TAX AMOUNT

Chapter 3, Attachment C, Securitization Fixed Recovery Charge and Fixed Recovery Tax Amount

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	**Fixed Recovery Charge (FRC)**											
2	Annual Debt Service	$ 235.1	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 22.6
3	Servicing & Administrative Fees (PG&E)	$ 1.0	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 0.6
4	Rating Agency Fees	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
5	Other Ongoing Financing Costs[1]	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.4
6	Uncollectibles for FRC	$ 0.8	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 0.1
7	**Annual FRC RRQ**	$ 237.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 23.7
8	**Fixed Recovery Tax Amounts (FRTA)**											
9	Return on Deferred Tax Balance	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ -
10	Uncollectible on FRTA	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ -
11	Total Revenue Requirement (FRC+FRTA)	$ 237.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 23.7
12	Revenue fees on the total Revenue requirement	$ 1.8	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 2.4	$ 0.2
13	**Total RRQ**	**$ 239.4**	**$ 319.0**	**$ 319.0**	**$ 319.0**	**$ 319.0**	**$ 319.0**	**$ 319.0**	**$ 319.0**	**$ 319.0**	**$ 319.0**	**$ 23.9**

1Accountant's, Legal, Trustee/Trustee's Counsel, Independent Managers', Printing/Edgarizing and Miscellaneous Fees, and Return on Equity Contribution to SPE

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

CUSTOMER BENEFITS

WITNESSES: DIVYA RAMAN, KAMRAN RASHEED

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
CUSTOMER BENEFITS
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
CUSTOMER BENEFITS
WITNESSES: DIVYA RAMAN, KAMRAN RASHEED

A. Introduction (D. Raman & K. Rasheed)

This chapter develops and presents in Section B the statutorily-mandated comparison of the revenue required from customers for Pacific Gas and Electric Company (PG&E) to recover the Authorized Amount under traditional utility financing mechanisms versus the revenue required to recover such costs if financed with securitized debt. In addition to this statutory comparison, this chapter presents in Section C an assessment of the present value of the proposed Wildfire Rate Relief Bonds transaction relative to the status quo where customers forego the 2025 bill credit and pay the 2023 and 2024 vegetation management costs in annual rates.

These revenue requirement analyses rely on models that are presented in annualized form to simplify the presentation and show the overall savings from using the securitized debt financing. For simplicity, and to allow for evaluation on a comparable basis, the revenue requirements are provided without regard to deferred taxes. Those items are discussed in detail in Chapter 5, Taxation (T. Wedlake), and shown in Attachment C to Chapter 3, Transaction Overview (M. Klemann).

Finally, this chapter details how the benefits of vegetation management expenses extend across the tenor of the proposed bonds. As a result, the proposed bonds equitably align the rate impact on future customers from securitization with long-term benefits.

B. Comparison Between Securitized Debt Financing and Traditional Utility Financing Under Section 850.1(a)(1)(A)(ii)(III) (D. Raman)

Section 850.1(a)(1)(A)(ii)(III) requires that the proposed securitization

> would reduce, to the maximum extent possible, the rates on a present value basis that consumers within [PG&E's] service territory would pay as compared to the use of traditional utility financing mechanisms, which shall

be calculated using the electrical corporation's corporate debt and equity in the ratio approved by the commission at the time of the financing order."[1]

The statute dictates the calculation and makes clear that the securitization financing cost must be compared to the authorized return on rate base. This is consistent with how the California Public Utilities Commission has previously applied Section 850.1(a)(1)(A)(ii)(III), even where the costs to be financed using securitization are not otherwise eligible to earn a full rate of return.[2]

Thus, for purposes of Section 850.1(a)(1)(A)(ii)(III), PG&E compares the annual revenue required from customers to recover the Authorized Amount for the two different methods of financing, which are described below and shown in Chapter 4, Attachments A and B. The comparison is also described below and shown in Chapter 4, Attachment C.

1. Revenue Requirements Assuming Traditional Utility Financing Mechanisms

PG&E calculates the Authorized Amount annual revenue requirement based on the following assumptions for traditional rate base financing and cost recovery:

- The principal costs of the Authorized Vegetation Management (VM) Expenses are amortized on a straight line basis over a 10-year period beginning on January 1, 2025;
- The rate of return allowed on the unrecovered balance of the Authorized VM expenses is PG&E's currently authorized return on rate base (7.8 percent) with the associated income tax gross up; and
- Since PG&E does not collect all the revenue that is billed, an allowance for uncollectible accounts expenses is added to the debt service.[3],[4]

Chapter 4, Attachment A presents the revenue requirements for PG&E to recover the Authorized Amount using traditional utility financing

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[1] Public Utilities Code § 850.1(a)(1)(A)(ii)(III).

[2] E.g., Decision (D.) 21-05-015 (PG&E Rate-Neutral). See D.20-11-007 (Southern California Edison Company (SCE) Initial Assembly Bill (AB) 1054 Capex) at 43, n.28. See also D.24-02-011 (PG&E Third AB 1054 Capex); D.22-08-004 (PG&E Second AB 1054 Capex); D.21-06-030 (PG&E Initial AB 1054 Capex).

[3] Upfront Financing Costs are not included in Chapter 4, Attachment A.

[4] Revenue Fees and Uncollectibles (RF&U) Electric Revenue factor approved in Advice Letter (AL) 4839-G/7086-E p. 2.

mechanisms over 10 years. Based on these assumptions, the illustrative revenue requirement is expected to decrease from approximately $464.0 million in year one (2025) to approximately $250.1 million in Year 10 (2034).

2. Revenue Requirements Assuming Securitized Debt Financing

PG&E estimates the annual revenue requirements under the assumptions described in Chapter 3, Transaction Overview (M. Klemann), and as shown in Chapter 3, Attachment C thereto, which include Upfront Financing Costs and Ongoing Financing Costs, and which use an interest rate on the securitized debt of 5.33 percent. Since PG&E does not collect all the revenue that is billed, an allowance for uncollectible accounts expenses is added to the revenue requirement.

Chapter 4, Attachment B presents the Wildfire Rate Relief Fixed Recovery Charge (WRRFRC) revenue requirements for PG&E to recover the Authorized Amount through securitized debt. Based on these assumptions, the WRRFRC revenue requirement is expected to be approximately $316.6 million annually from 2025 through 2034. Chapter 3, Attachment C presents the total revenue requirement including the fixed recovery tax amount and Revenue fees is approximately $319.0 million.

3. Revenue Requirement Savings From Securitization as Compared to Traditional Utility Financing

Consistent with Section 850.1(a)(1)(A)(ii)(III), the revenue requirement savings for each year associated with securitizing the Authorized Amount, assuming the two different financing mechanisms, are summarized in Chapter 4, Attachment C on an annual basis, on an accumulated nominal basis, and as the present value of the net revenue requirement reductions.

Lines 2-3 in Chapter 4, Attachment C show the revenue requirements under the two financing mechanisms described in Section B.1-2. Lines 4-5 show the annual revenue requirement savings assuming traditional utility financing mechanisms relative to securitized debt financing.

Line 5 of Chapter 4, Attachment C shows the nominal savings are approximately $436.2 million relative to traditional utility financing mechanisms over the 10-year period. Using a discount rate of 7.8 percent,[5] the present value of the savings is approximately $452.6 million (line 7). Thus, consistent with Section 850.1(a)(1)(A)(ii)(III), on a present value basis, the proposed securitization would reduce the charges necessary to finance the Authorized Amount compared to the use of traditional utility financing mechanisms.

C. Comparison Between the Proposed Wildfire Rate Relief Bond Financing Transaction and "No Transaction" Scenarios (D. Raman)

In addition to the comparison required by Section 850.1(a)(1)(A)(ii)(III) discussed above, PG&E also compares "transaction" and "no transaction" scenarios. This evaluates the proposed Wildfire Rate Relief Bond financing transaction—which includes a bill credit beginning in April 2025 and ending in March 2026 and payment of WRRFRCs over the 10-year life of the bonds—as compared to the status quo—where customers pay the 2023 and 2024 VM expenses in annual rates and forego the bill credit associated with the proposed financing transaction.

1. Revenue Requirements Assuming the Proposed Wildfire Rate Relief Bond Financing Transaction

PG&E estimates the net revenue requirements associated with the proposed Wildfire Rate Relief Bond financing transaction in Chapter 4, Attachment D. This includes both the immediate bill relief provided in 2025 as well as annual revenue requirements to recover the Authorized Amount through securitized debt under the assumptions described in Chapter 3, Transaction Overview (M. Klemann), and as shown in Chapter 3, Attachment C thereto, which include Upfront Financing Costs, and Ongoing Financing Costs, and which use an interest rate on the securitized debt of 5.33 percent. Since PG&E does not collect all the revenue that is billed, an allowance for uncollectible accounts expenses is added to the revenue requirement.[6]

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5 PG&E assumes that the discount rate should be applied to the entire period of cost recovery and should be set equal to PG&E's authorized return on rate base, which is currently 7.8 percent. See D.23-01-002; ALs 4813-G/7046-E.

6 RF&U Electric Revenue factor approved in AL 4839-G/7086-E p. 2.

Thus, Attachment D shows a present value estimate of the impact of the proposed financing transaction on customers, as compared to the "no transaction" status quo where customers forego the bill credit in 2025. The present value analysis uses a discount rate of 7.8 percent.[7] Attachment D also shows the nominal annual and cumulative impacts of the proposed financing transaction as compared to the "no transaction" status quo.

2. The Proposed Wildfire Rate Relief Bonds Benefit Customers

The analysis in Attachment D shows the financial benefits of the proposed Wildfire Rate Relief Bonds for customers on a present value basis of $122 million, relative to the status quo "no transaction" scenario. This present value analysis does not include the other benefits of the financing transaction for customers, which are described further in Chapter 1, Introduction (M. Becker). In particular, and as noted in Chapter 7, Rate Proposal (B. Kolnowski), the proposed transaction provides an immediate and significant bill credit to residential customers of an average $15.75 per month from April 2025 to March 2026, or $190 per year. In so doing, PG&E's proposal directly responds to stakeholder concerns regarding the affordability of current customers bills.

D. The Proposed Transaction Aligns Cost Incidence With the Long-Term Benefits of Vegetation Management (K. Rasheed)

The proposed Wildfire Rate Relief Bond financing transaction also equitably distributes the costs of vegetation management among customers such that the incidence of some of these vegetation management costs will now occur in-line with their associated real-world mitigation and cost reduction benefits. PG&E's vegetation management activities, which are performed in accordance with Utility Standard TD-7102S, *Distribution Vegetation Management Program* (see Attachment E), produce benefits that range from at least a year to permanent duration. Cost savings benefits are achieved by bundling work and enhancing processes to increase situational awareness of regional tree growth and failure trends.

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7 PG&E assumes that the discount rate should be applied to the entire period of cost recovery and should be set equal to PG&E's authorized weighted average cost of capital, which is currently 7.8 percent. See D.23-01-002; ALs 4813-G/7046-E.

For instance, pruning/trimming in conformance with Utility Arborist Association and American National Standards Institute (ANSI) standards, the California Power Line Fire Prevention Field Guide, and Utility Best Management Practices, *Tree Risk Assessment and Abatement for Fire-Prone States and Provinces in the Western Region of North America* (see Attachment F and Attachment G) yields benefits that last at a minimum one year and usually multiple years, depending on the tree species and growth pattern of the tree, maturity of the tree, and its proximity to electric facilities. As one example, pruning a limb on a large oak tree located near electrical conductors back to the main trunk would achieve multiple years of clearance, as compared to merely trimming it to a lateral branch, which could lead to regrowth back towards the conductors between inspection cycles. Likewise, side trimming most conifers to the trunk, rather than to mid-branch, also tends to yield sustained clearance benefits. Targeted pruning near the branch-bark-ridge, as recommended under ANSI A300 Tree Care Standards that guide PG&E, likewise helps minimize tree regrowth or divert growth away from conductors after pruning (see Attachment H and Attachment J).

Tree *removal* is another vegetation management tool that can result in even longer-term benefits than pruning. Tree removal yields mitigation benefits of permanent or extended duration, depending on the tree species and stump treatment for those species capable of resprouting (see Attachment H and Attachment I). Over the past four years, including in 2023 and year-to-date 2024, PG&E has utilized its vegetation management programs to expand the focus on tree removal as a component of vegetation management, especially on trees with incompatible placement or rapid growth patterns (see Table 4-1). When pruning is unlikely to yield multi-year benefits and would necessitate repeated efforts on an annual or biannual basis, removal is the preferred option under PG&E's vegetation management program. Tree removal in areas underneath or in proximity to conductors, instead of trimming/pruning at certain heights, reduces the overall amount of tree work required in the future. Further strengthening mitigation efforts around regrowth originating from historical tree removal of trees with potential to re-sprout will sustain the long-term benefits of removals. This enhances the long-term mitigation benefits of PG&E's vegetation management activities and avoids future costs associated with pruning/trimming taller mature trees encroaching on energized conductors (see Attachment I and Attachment J).

TABLE 4-1
TREE WORK COMPLETED

Tree Work Completed	Routine Patrol	Second Patrol	EVM	VMOM	TRI	FTI	TOTALS
2020 Grand Total	**1,587,793**	**59,917**	**167,221**	-	-	-	**1,814,931**
2020 Trims	1,348,643	21,925	46,242				**1,416,810**
2020 Removals	239,150	37,992	120,979				**398,121**
2021 Grand Total	**1,458,612**	**32,626**	**336,018**	-	-	-	**1,827,256**
2021 Trims	1,279,577	10,322	57,682				**1,347,581**
2021 Removals	179,035	22,304	278,336				**479,675**
2022 Grand Total	**1,091,223**	**120,395**	**396,395**	**7,198**	-	-	**1,615,211**
2022 Trims	945,136	35,179	49,860	6,530			**1,036,705**
2022 Removals	146,087	85,216	346,535	668			**578,506**
2023 Grand Total	**1,140,614**	**139,872**	-	**8,164**	**15,599**	**2,272**	**1,306,521**
2023 Trims	1,016,950	41,369		4,687	-	269	**1,063,275**
2023 Removals	123,664	98,503		3,477	15,599	2,003	**243,246**

Legend	
Routine Patrol	Annual pre-inspection and associated tree work as a baseline control program
Second Patrol	Formerly known as CEMA and/or Tree Mortality program. Targeted to follow Routine Patrol by approximately 6 months in high risk areas to address mid-cycle changes in tree conditions.
EVM	Enhanced Vegetation Management program (2019-2022) designed as risk mitigation
VMOM	Vegetation Management for Operational Mitigation program incorporates targeted proactive and reactive inspection and tree mitigations specific to regional outage trends driven by Enhanced Powerline Safety Settings (EPSS) program
TRI	Tree Removal Inventory program is follow up mitigation on trees identified during the EVM program but not worked due to permitting, environmental or other constraints.
FTI	Focused Tree Inspection pgoram is a-data informed and risk-model-prioritized program designed to target areas with a demonstrated higher frequency of vegetation caused outages. It utilizes TRAQ-certified Arborists to perform Level 2 inspections on strike trees.

Beyond pruning/trimming and removal, PG&E's other vegetation management programs also yield long-term benefits. For example, the wood management program reduces natural fuel for wildfires for an extended period while also improving emergency response access for first responders.

Because many of PG&E's current vegetation management activities provide multi-year benefits or benefits of permanent duration, the proposed Wildfire Rate Relief Bonds help to address the disproportionate cost incidence on current customers, and more fairly allocate these vegetation management costs between current and future customers by better aligning recovery of the costs in rates with the real-world mitigation benefits of the work.

E. Conclusion (D. Raman)

For the foregoing reasons, the Wildfire Rate Relief Bonds satisfy the requirements of Section 850.1(a)(1)(A)(ii)(III) and will benefit PG&E's customers.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

RECOVERY OF WILDFIRE MITIGATION CAPITAL COSTS, TRADITIONAL FINANCING

Chapter 4, Attachment A, Recovery of Wildfire Mitigation Capital Costs, Traditional Financing

No		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Capital Asset Rev Req											
2	Interest	$ 49.5	$ 44.3	$ 39.1	$ 33.9	$ 28.7	$ 23.5	$ 18.3	$ 13.0	$ 7.8	$ 2.6	$ 0.0
3	Preferred Dividend	$ 0.6	$ 0.6	$ 0.5	$ 0.4	$ 0.4	$ 0.3	$ 0.2	$ 0.2	$ 0.1	$ 0.0	$ 0.0
4	Earning for Common	$ 124.5	$ 111.4	$ 98.3	$ 85.2	$ 72.1	$ 59.0	$ 45.9	$ 32.8	$ 19.7	$ 6.6	$ 0.0
5	Taxes on Return	$ 48.6	$ 43.5	$ 38.4	$ 33.3	$ 28.2	$ 23.0	$ 17.9	$ 12.8	$ 7.7	$ 2.6	$ 0.0
6	Return	$ 223.3	$ 199.8	$ 176.3	$ 152.8	$ 129.3	$ 105.8	$ 82.3	$ 58.8	$ 35.3	$ 11.8	$ 0.0
7	Principal Amortization	$ 235.6	$ 235.6	$ 235.6	$ 235.6	$ 235.6	$ 235.6	$ 235.6	$ 235.6	$ 235.6	$ 235.6	$ -
8	Subtotal	$ 458.9	$ 435.4	$ 411.9	$ 388.4	$ 364.9	$ 341.4	$ 317.9	$ 294.4	$ 270.9	$ 247.4	$ 0.0
9	Uncollectibles	$ 1.6	$ 1.5	$ 1.4	$ 1.4	$ 1.3	$ 1.2	$ 1.1	$ 1.0	$ 1.0	$ 0.9	$ 0.0
10	Revenue Fees	$ 3.5	$ 3.3	$ 3.1	$ 3.0	$ 2.8	$ 2.6	$ 2.4	$ 2.2	$ 2.1	$ 1.9	$ 0.0
11	Total Rev Req	$ 464.0	$ 440.3	$ 416.5	$ 392.7	$ 369.0	$ 345.2	$ 321.4	$ 297.6	$ 273.9	$ 250.1	$ 0.0
12	Reg Asset Balance											
13	BOY Asset Bal	$ 2,356	$ 2,120	$ 1,885	$ 1,649	$ 1,414	$ 1,178	$ 942	$ 707	$ 471	$ 236	$ 0
14	Amortization	$ (236)	$ (236)	$ (236)	$ (236)	$ (236)	$ (236)	$ (236)	$ (236)	$ (236)	$ (236)	$ -
15	EOY Asset Balance	$ 2,120	$ 1,885	$ 1,649	$ 1,414	$ 1,178	$ 942	$ 707	$ 471	$ 236	$ 0	$ 0

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT B

SECURITIZATION FIXED RECOVERY CHARGE

Chapter 4, Attachment B, Securitization Fixed Recovery Charge

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1 Fixed Recovery Charge (FRC)											
2 Annual Debt Service	$ 235.1	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 313.5	$ 22.6
3 Servicing & Administrative Fees (PG&E)	$ 1.0	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 0.6
4 Rating Agency Fees	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
5 Other Ongoing Financing Costs[1]	$ 0.6	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.7	$ 0.4
6 Uncollectibles for FRC	$ 0.8	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 1.1	$ 0.1
7 Annual FRC RRQ	$ 237.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 316.6	$ 23.7

[1]Accountant's, Legal, Trustee/Trustee's Counsel, Independent Managers', Printing/Edgarizing and Miscellaneous Fees, and Return on Equity Contribution to SPE

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT C

NET REDUCTION IN RRQ FOR USE OF SECURITIZED BONDS

IN COMPARISON WITH CONVENTIONAL FINANCING

Chapter 4, Attachment C, Net Reduction in RRQ for use of Securitized Bonds in comparsion with Conventional Financing

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1												
2	RRQ: Conventional Financing	$464.0	$440.3	$416.5	$392.7	$369.0	$345.2	$321.4	$297.6	$273.9	$250.1	$0.0
3	RRQ: Securitized Debt Financing	$239.4	$319.0	$319.0	$319.0	$319.0	$319.0	$319.0	$319.0	$319.0	$319.0	$23.9
4	Annual Savings v Conventional Financing	$224.7	$121.2	$97.5	$73.7	$49.9	$26.2	$2.4	-$21.4	-$45.2	-$68.9	-$23.9
5	Cumulative Annual Savings v Conventional Financing	$224.7	$345.9	$443.4	$517.1	$567.0	$593.2	$595.6	$574.2	$529.0	$460.1	$436.2
6												
	Present Value of Annual Savings v Conventional Rate											
7	**Base Financing**	**$452.6**										
8												
9	Discount Rate[1]:	7.80%										

[1]PG&E Weighted average cost of capital

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
ATTACHMENT D
NET REDUCTION IN RRQ FOR USE OF SECURITIZED BONDS
IN COMPARISON WITH STATUS QUO REVENUES

Chapter 4, Attachment D, Net Reduction in RRQ for use of Securitized Bonds in comparison with Status Quo Revenues

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1												
2	RRQ: GRC Authorized Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	RRQ: Securitized Debt Financing	$ 239.4	$ 319.0	$ 319.0	$ 319.0	$ 319.0	$ 319.0	$ 319.0	$ 319.0	$ 319.0	$ 319.0	$ 23.9
4	RRQ: Rate Reduction	$ (2,382.2)	$ -									
5	Annual Savings v Conventional Financing	$ 2,142.8	$ (319.0)	$ (319.0)	$ (319.0)	$ (319.0)	$ (319.0)	$ (319.0)	$ (319.0)	$ (319.0)	$ (319.0)	$ (23.9)
6	Cumulative Annual Savings v Conventional Financing	$ 2,142.8	$ 1,823.8	$ 1,504.8	$ 1,185.8	$ 866.8	$ 547.7	$ 228.7	$ (90.3)	$ (409.3)	$ (728.4)	$ (752.3)
7												
8	**Present Value of Annual Savings v GRC Authorized Revenues**	**$ 122.0**										
9												
10	Discount Rate[1]:	7.8%										

[1]PG&E Authorized Weighted average cost of capital

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT E

UTILITY STANDARD: TD-7102S DISTRIBUTION VEGETATION MANAGEMENT PROGRAM

Distribution Vegetation Management Program

SUMMARY

This utility standard describes the requirements for the Pacific Gas and Electric Company (PG&E) Distribution Vegetation Management (VM) program. This program maintains vegetation clearances in accordance with CPUC General Order (G.O.) 95, Rule 35, CPUC General Order (G.O.) 95, Rule 18, State of California Public Resource Code (PRC) 4293 and 4295.5. The intent of the Distribution VM program is to prevent encroachment into minimum distance requirements (MDR), to reduce the risk of reasonably foreseeable outages and fire ignitions and to ensure compliance with State mandates.

TARGET AUDIENCE

Vegetation Asset Strategy and Analytics (VASA)

VM Operations

Quality Management (QM)

TABLE OF CONTENTS

Distribution Vegetation Management Program

REQUIREMENTS

1 Regulatory Requirements

1.1 PG&E recognizes and requires compliance with the following regulatory requirements and recommendations:

1. California Public Utilities Commission (CPUC) General Order 95, Rule 35 (G.O. 95, Rule 35)

2. G.O. 95, Rule 35 in Appendix E, which recommends a minimum 12-feet of clearance at time of trim in High Fire-Threat District (HFTD). PG&E extends this minimum clearance recommendation to tree work within HFRA. Reasonable vegetation management practices may make it advantageous for the purposes of public safety or service reliability to obtain greater clearances.

3. G.O. 95, Rule 18 in Appendix I which outlines Priority Levels and Safety Hazards

4. State of California Public Resources Code (PRC) 4293 and 4295.5

5. California Code of Regulation (CCR) Title 14 Sections 1250, 1251, 1252, 1253, 1256, 1257 and 1258

6. CPUC Resolution ESRB-4 (June 12, 2014), which directs investor-owned electric utilities to take remedial measures to reduce the likelihood of fires started by or threatening utility facilities.

2 PG&E Requirements and Expectations

2.1 Annual Patrol inspects all overhead electric distribution primary and secondary conductors (including idle), and facilities (excluding service drops).

2.2 Second Patrol inspects all overhead electric distribution primary and secondary conductors (including idle), and facilities (excluding service drops) within defined geographic areas (see Appendix B, "Second Patrol Defined Geographic Area").

2.3 Adhere to regulations in Section 1, "Regulatory Requirements" above and relying on the criteria and guidance appearing in Appendix A of this document, to identify and act with respect to the following conditions:

- Vegetation that has or may encroach the MDR based on anticipated growth rates before the next annual work cycle (see Appendix A, Minimum Distance Requirements [MDR]).

- Vegetation (categorized as either a whole tree or portion of tree) that may fall into or otherwise impact PG&E electric facilities.

- Any vegetation that is causing abrasion or significant strain to the secondary conductors.
- When a third-party utility or non-utility third party causes a condition that negatively impacts PG&E's facilities is observed, then follow TD-2014S "Third-Party Notification and Resolution of Potential Violations and Safety Hazards" and TD-2015S, "Notification to Third-Party Non-Utility of Nonconformance."

2.4 Perform tree work to adhere to the regulations in Section 1, "Regulatory Requirements" above and to maintain the MDR around overhead electric distribution conductors (including idle) at any position of the conductor, specifically:

- On primary lines (greater than 750 volts) to include underbuilt construction.
- On secondary lines (pole-to-pole less than 750 volts).

2.5 Perform tree work to mitigate vegetation (categorized as either a whole tree or portion of tree) that is imminent and probable to fall into or otherwise impact PG&E electric facilities (including idle), following regulations in Section 1, "Regulatory Requirements" above.

3 Roles and Responsibilities

3.1 The Vegetation Asset Strategy and Analytics (VASA) team is responsible for risk-informed Scope of Work development.

3.2 The VM Operations team is responsible for creating procedures and processes to meet the expectations in this standard and to support compliance with the regulatory requirements and for the execution of day-to-day operational tasks to meet the expectations in this standard and compliance obligations.

1. The primary responsibilities for the VM Operations leadership team are to:
   - Monitor and manage the inspection and tree work schedule adherence throughout the year to ensure compliance and prevent encroachment into MDR.
   - Support the workforce to manage and resolve constraints and interference, mitigation of issues preventing work completion, adherence to the expectations set in this standard and supporting procedures.
2. The primary responsibility for vegetation management inspectors (VMI) is to inspect and prescribe necessary vegetation work in accordance with regulatory obligations and industry and PG&E standards.
3. The primary responsibility for tree contractors (TC) is to review clearance prescriptions and execute vegetation work in accordance with regulatory obligations and industry and PG&E standards.

3.3 The Quality Management team conducts work performance reviews and assessments, verification of work completion, and quality assurance audits.

4 Industry Standards and Arboriculture Practices

4.1 The PG&E VM program shall consider the use of the industry standards and best management practices such as, but not limited to, the documents listed in the “Reference Documents” section.

5 Utility Arboriculture Cycles

5.1 Annual Patrol and Second Patrol VM activities occur based on two utility arboriculture cycles, Inspection Cycle and Work Cycle.

5.2 During the Inspection Cycle, vegetation is inspected for adherence to the regulatory requirements and recommendations in Section 1, “Regulatory Requirements” and PG&E requirements and expectations in Section 2, “PG&E Requirements and Expectations “of this document.

- As necessary, vegetation work prescriptions are made to ensure that vegetation remains in compliance.
- The Annual Patrol cycle stabilization is performed to maintain compliance and manage risk. Deviations from an annual patrol cycle need to be documented.
- The Annual Patrol cycle is planned on an annual timeline but allows for unforeseen schedule changes to the cycle if a constraint or external factors is documented.
- The Second Patrol inspection cycle is typically planned and patrolled with a six-month offset from the annual patrol inspection date. This timing can vary due to operational or external factors.

5.3 During the Work Cycle, vegetation pruning and felling of trees is performed to ensure compliance with the regulatory requirements and recommendations in Section 1, “Regulatory Requirements” and PG&E requirements and expectations in Section 2, “PG&E Requirements and Expectations “of this document.

1. This work is to be completed prior to vegetation breaching compliance. Beginning in the 2024 inspection cycle, unless a constraint or external factors is documented, tree work shall be completed within one year of identification.
   a. Priority work shall be addressed according to TD-7102P-17, “Vegetation Management Priority Tag Procedure.”
2. This cycle is planned on an annual timeline but allows for unforeseen schedule changes to the cycle if a constraint or external factor is documented.

6 Annual Planning

6.1 Workplans are created annually in advance of initiation of the Inspection Cycle.

This process identifies opportunities to adjust the schedule of circuits or circuit segments based on the most current data and information available. Data and information available can include, but is not limited to, risk models, predictive models, input or requests from local experts, environmental considerations, tree species growth or failure rates, outage and ignition data, and coordination with wildfire mitigations outside vegetation management.

7 Records Management and Data Integrity

7.1 The Distribution Vegetation Management program is required to document its work and to create and complete records per Records and Information Management, below in this standard.

8 Exceptions

8.1 Variances to this standard must be approved by the Vegetation Management Vice President (VP) and the Wildfire & Enterprise Risk Management Vice President (VP).

END of Requirements

DEFINITIONS

Abrasion: Damage to insulation resulting from friction between vegetation and conductors. Scuffing or polishing of the insulation or covering is not considered abrasion.

Strain: Is present when vegetation contact significantly compromises the structural integrity of supply or communication facilities. Contact between vegetation and conductors is not considered strain.

Constraint: A situation that occurs when a customer, property owner, or agency obstructs or delays PG&E pre-inspection work or the completion of the intended tree work.

External Factors: Events and conditions that are beyond the control of Vegetation Management.

Facility (Distribution): The components of the electric distribution overhead system, including pole/support structure, primary conductors [4 kilovolts (kV) and less than 60 kV – with the majority being between 4 kV to 21 kV], voltage regulating equipment, switching equipment, transformers, and secondary conductors (operates under 750 V and supply ranging from 120 V to 480 V). Refer to TD-8105, "Distribution Line Overhead Asset Management Plan" for additional details.

High Fire-Threat District (HFTD): High Fire-Threat District means those areas comprised of the following:

(1) (1) Zone 1 is Tier 1 of the latest version of the United States Forest Service (USFS) and CAL FIRE's joint map of Tree Mortality High Hazard Zones (HHZs). (Note: The Tree Mortality HHZs Map may be revised regularly by the USFS and CAL FIRE.)

(2) (2) Tier 2 is Tier 2 of the CPUC Fire-Threat Map.

(3) (3) Tier 3 is Tier 3 of the CPUC Fire-Threat Map.

High Fire Risk Area (HFRA): A purpose-built map for use in scoping Public Safety Power Shutoff events identifying areas where risk factors for the potential of catastrophic fire from utility infrastructure ignition during offshore wind events is higher.

Idle: Facilities that do not currently serve a customer load and may be energized or de-energized temporarily or permanently. All idle facilities are considered active until they are abandoned. For this standard, abandoned facilities are included in this definition. Abandoned facilities are physically isolated from all other energized conductors, equipment, or facilities and are determined by PG&E to have no foreseeable future use.

Inspection: An organized and systematic examination.

Minimum Distance Requirement (MDR): Distance to maintain separation between vegetation and distribution conductors in Local Responsibility Areas (LRAs), State Responsibility Areas (SRAs) and California's High Fire-Threat District (HFTD), in accordance with CPUC General Order (G.O.) 95, Rule 35 and Public Resource Code (PRC) 4293.

Portion of tree: A part of a tree. Such as a limb, branch, or section of the canopy.

Prescription: A recommendation of tree work to be performed. Information provided typically includes type of pruning (e.g., top-trim, or side-trim), how much of the tree to be trimmed or removed, and any other information that would be helpful for the tree contractor.

Priority: Conditions that may result from either encroachment into the Pacific Gas and Electric Company (PG&E) minimum clearance requirement or from potential tree or limb failure. The following time constrains apply to each of the priority conditions:

- Priority 1 tags must be mitigated within 24 hours of identification when reported.
- Priority 2 tags must be mitigated within 20 business days, unless constrained

Prune (Trim): Removing branches from a tree or other plant using approved practices, to achieve a specified objective.

Secondary Conductor: Conductors operated at a transformer's secondary voltage (< 750 volts) to distribute power to end-use customers.

Service Drop: Service Drop means that portion of a circuit located between a pole line and a building, a structure or a service and meter pole. (Section 23.4 of GO 95)

Underbuilt: Electric distribution lines located directly under and parallel with transmission lines and attached to the same pole or structure.

IMPLEMENTATION RESPONSIBILITIES

The Vegetation Asset Strategy and Analytics team is responsible for the development and communication of this standard to VM Operations leadership, as well as the periodic review of this document. VM Execution is responsible for the distribution of this standard by providing training and conducting regular reviews to ensure adherence.

GOVERNING DOCUMENT

Utility Policy TD-05, "Vegetation Management Policy"

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

California Public Utilities Commission (CPUC), General Order 95, Rule 35

California Public Utilities Commission (CPUC), General Order 95, Rule 35 in Appendix E

California Public Utilities Commission (CPUC), CPUC General Order 95, Rule 18

California Public Utilities Commission (CPUC), General Order 95, Rule 18 in Appendix I

California Public Resources Code (PRC), sections 4293 and 4295.5

California Code of Regulations (CCR), Title 14, sections 1250, 1251, 1252, 1253, 1256, 1257 and 1258

CPUC Resolution ESRB-4 (June 12, 2014)

Records and Information Management:

PG&E records are company assets that must be managed with integrity to ensure authenticity and reliability. Each Line of Business (LOB) must manage Records and Information in accordance with the Enterprise Records and Information (ERIM) Policy, Standards and Enterprise Records Retention Schedule (ERRS). Each Line of Business (LOB) is also responsible for ensuring records are complete, accurate, verifiable and can be retrieved upon request. Refer to GOV-7101S, "Enterprise Records and Information Management Standard" for further records management guidance or contact ERIM at Enterprise_RIM@pge.com."

REFERENCE DOCUMENTS

Developmental References:

NA

Supplemental References:

International Society of Arboriculture (ISA) Best Management Practices (BMPs)

ANSI A300 Part 9, "Tree Risk Assessment Standard," by E. Thomas Smiley, Nelda Matheny, and Sharon Lilly and its companion publication, "Utility Tree Risk Assessment," by John W Goodfellow, that describes the levels and scope of tree risk assessment.

Cal Fire Power Line Fire Prevention Field Guide

Utility Arborist Association (UAA) Best Management Practices for Tree Risk Assessment and Abatement

Utility Standard RISK-6300S, "Quality Management Audit Standard"

Utility Standard TD-2459S, "Management of Idle Electric Distribution Lines"

TD-2014S, "Third-Party Notification and Resolution of Potential Violations and Safety Hazards"

TD-2015S, "Notification to Third-Party Non-Utility of Nonconformance"

APPENDICES

Appendix A, Minimum Distance Requirements (MDR)

Appendix B, Second Patrol Defined Geographic Area

ATTACHMENTS

NA

DOCUMENT RECISION

Utility Standard TD-7102S, "Distribution Vegetation Management Standard (DVMS)," Rev. 1, 09/04/2015 (original publication)

Distribution Vegetation Management Program

DOCUMENT APPROVER

Michael Seitz, VP, Vegetation Management

Russell Prentice, VP, Wildfire & Enterprise Risk Management

[redacted], Sr. Director, Wildfire Risk Management

DOCUMENT OWNER

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[redacted], Principal Asset Management Specialist, Vegetation Asset Strategy and Analytics

REVISION NOTES

Where?	What Changed?
Entire document	This is a complete rewrite of this document.

Distribution Vegetation Management Program

Appendix A, Minimum Distance Requirements (MDR)

Page 1 of 1

Jurisdiction	LRA (non-HFTD) Applicable year-round	HFTD Applicable year-round	SRA Applicable during fire season	FRA (When on USFS property) Applicable during fire season
Regulation	G.O. 95, Rule 35	G.O. 95, Rule 35	PRC 4293	PRC 4293
Minimum Distance Requirement for Primary Conductors greater than 750 volts	18-inches	4-feet	4-feet	4-feet
Requirement for Conductors less than 750 volts	Prune if strain or abrasion to the conductor is observed.			

- If LRA overlaps with HFRA, PG&E MDR guidance is consistent with HFTD requirements, unless otherwise constrained.
- If FRA is not on USFS Property, PG&E MDR guidance is consistent with HFTD requirements, unless otherwise constrained.
- Vegetation must not encroach within the minimum distance at any time between inspection and one year or next scheduled Work Cycle.
- Depending on span length, facility construction and conductor material, potential sag and sway can range from 1-foot at quarter-span to 4-feet at mid-span.

Appendix B, Second Patrol Defined Geographic Area
Page 1 of 1

Inspection area details

- **State Responsibility Area (SRA):** The area in the state where the State of California (CAL FIRE) has the primary financial responsibility for the prevention and suppression of wildland fires.
- **Federal Responsibility Area (FRA):** Those lands administered or controlled by the Federal Government for which the Federal Agencies have administrative and protection responsibility.
  - **High Fire-Threat District (HFTD):** High Fire-Threat District means those areas comprised of the following:
    - (1) Zone 1 is Tier 1 of the latest version of the United States Forest Service (USFS) and CAL FIRE's joint map of Tree Mortality High Hazard Zones (HHZs). (Note: The Tree Mortality HHZs Map may be revised regularly by the USFS and CAL FIRE.)
    - (2) Tier 2 is Tier 2 of the CPUC Fire-Threat Map.
    - (3) Tier 3 is Tier 3 of the CPUC Fire-Threat Map.
  - **High Fire Risk Area (HFRA):** A purpose-built map for use in scoping Public Safety Power Shutoff events identifying areas where risk factors for the potential of catastrophic fire from utility infrastructure ignition during offshore wind events is higher.
  - **Wildland Urban Interface (WUI):** Layer produced by Silvis Labs that clipped to Local Responsibility Areas (LRA). Intermix WUI are areas where housing and vegetation intermingle; interface WUI are areas with housing in the vicinity of contiguous wildland vegetation.
  - **Fire Hazard Severity Zone (FHSZ):** A layer produced by CAL FIRE and the Resource Assessment Program (FRAP) using data and models describing development patterns, potential fuels over a 30-50 yeartime horizon, expected fire behavior, and expected burn probabilities, to quantify the likelihood and nature of vegetation fire exposure. This second patrol project pertains only to the very high fire severity zone within the LRA.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT F

CALIFORNIA POWER LINE FIRE PREVENTION FIELD GUIDE

California Power Line Fire Prevention Field Guide

CALIFORNIA DEPARTMENT OF FORESTRY & FIRE PROTECTION
CAL FIRE
SINCE 1885

PUBLIC UTILITIES COMMISSION
STATE OF CALIFORNIA

2021 EDITION

Pacific Gas and Electric Company

SOUTHERN CALIFORNIA EDISON

SDGE
A Sempra Energy utility

California Power Line Fire Prevention Field Guide

2021

Thomas Porter
Director
CAL FIRE

Mike Richwine
State Fire Marshal

Marybel Batjer
President
CA Public Utilities Commission

The table of contents entries below are hyperlinked to their correlating sections in the document. Clicking on an entry will take you to its section.

ACRONYM DEFINITIONS

AB	Assembly Bill
BLM	Bureau of Land Management
CCR	California Code of Regulations
CPUC	California Public Utilities Commission
FRA	Federal Responsibility Area
GDB	Geodatabase
GIS	Geographic Information Systems
GO	General Order
HFTD	High Fire-Threat District
IOU	Investor-Owned Utility
kV	Kilovolt
LRA	Local Responsibility Area
PG&E	Pacific Gas & Electric
POU	Public-Owned Utility
PRC	Public Resources Code
PSPS	Public Safety Power Shutoff
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric
SRA	State Responsibility Area
USFS	United State Forest Service
WMP	Wildfire Mitigation Plan
WUI	Wildland Urban Interface

FOREWORD

This Power Line Fire Prevention Field Guide (hereinafter referred to as "Guide" or "Field Guide") outlines procedures to minimize the risk of catastrophic wildfires caused by electrical power lines and equipment. These procedures are based upon the studies and experiences of regulatory and fire protection agencies, electrical utilities, federal regulations and the laws of the State of California. These procedures are considered minimum guidelines. Field conditions may warrant more stringent procedures.

Except for sample copies retained for historical or reference purposes, the use of prior editions of this Guide shall be discontinued. This Guide is now considered a "living document." The online version of the Guide hosted on the CAL FIRE website at Power Line Fire Prevention Field Guide Link will have portions updated as necessary. For example, if electrical hardware is successful in the exemption testing process, the section of the Guide covering exemptions will be updated to reflect this change instead of waiting to update the section when the entire guide is updated farther in the future. For details on recent, ongoing, and pending updates, see the "Power Line Fire Prevention Field Guide Update Tracker Log" Excel spreadsheet, which is available on the CAL FIRE website hosting the Guide.

Regardless of varying interpretations of Guide language, the law must be obeyed. Thus, if there is any conflict between any statement in this Guide and any applicable statute, regulation or order, the statute, regulation or order shall take precedence. Some of the applicable statutes, regulations, and orders are set forth in the "Statutes, Regulations, Exemptions and State Laws" section of this Guide.

It is expected that all personnel who conduct inspections of power lines, or who prescribe hazard reduction work or other fire prevention measures will be thoroughly familiar with the contents of this Guide. They should refer to it regularly and observe the principles and procedures contained herein.

This Guide was developed with input from the California Department of Forestry and Fire Protection (CAL FIRE), the California Public Utilities Commission (CPUC), the United States Forest Service (USFS), the Bureau of Land Management (BLM), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas and Electric (SDG&E), and other electric utilities of California. Its purpose is to provide information and guidance to the personnel of regulatory and fire service agencies, and electrical utility personnel to enable them to accomplish at least minimum uniform application of power line fire prevention practices within the areas of their respective jurisdictions and responsibilities. The Guide is not to be used as a substitute for proper training but rather as a reference for personnel already familiar with power line inspections.

This edition of the Guide has been substantially revised not only to reflect changes in laws, regulations, procedures and technology but also to enhance its usefulness as a working field tool. This Guide is not intended to dictate to electrical utilities the methods they must use to construct and maintain their facilities. However, it does detail certain fire hazard reduction procedures to harden electrical utility infrastructure, thus increasing public safety.

OVERVIEW

The table of contents entries below are hyperlinked to their correlating sections in the document. Clicking on an entry will take you to its section.

Introduction

Importance of Collaboration

Collaboration and communication between regulatory and fire protection agencies and the electric utilities is of the utmost importance in the success of Wildfire Mitigation Plans (WMPs). Open lines of communication between all cooperators must be maintained. Regulatory and fire protection agencies need to provide immediate notification to electric utilities when fires involve their property and equipment. Electric utilities need to notify the fire agencies when their equipment or hardware might be the cause of fires unknown to regulatory and fire protection agencies. The CPUC also requires utility companies to annually report their fire ignitions. More information can be found at: California Public Utilities Commission Fire Incidents Data.

State and Federal Mandates

Due to extreme loss of property and lives from power line-caused fires and climate change, strict legislation has been passed to focus on this problem. Senate Bill 901 (SB 901) (2018) requires each Investor-Owned Utility (IOU) as well as each Public-Owned Utility (POU) to create, maintain, and follow a WMP. WMPs will include, among other things, details on utility vegetation management, system hardening, Public Safety Power Shutoffs (PSPS) and metrics to evaluate the effectiveness of these efforts. Each Investor-Owned Utility WMP will be reviewed by CPUC staff in consultation with CAL FIRE and eventually approved by the CPUC Wildfire Safety Division. Effective July 1, 2021 per AB111 The Wildfire Safety Division will be known as the Office of Energy Infrastructure Safety under the Natural Resources Agency. These plans will provide a conduit between the electrical utility providers and regulators and will improve power line safety in California. The USFS Southwest Region 5 office (includes California) has region-wide and individual agreements with utility providers that have facilities in the USFS Federal Responsibility Areas (FRA) of the state. These Operations and Maintenance agreements can be accessed by contacting USFS Region 5 through their website.

Systems of Record/GIS

Critical to the prevention of fires is knowing when, where and why they occur and building this information into a Geographic Information Systems (GIS) database that can be shared by regulatory and fire protection agencies and electric utilities. An expansive GIS database (including transmission/distribution lines and pole/tower and hardware location data) can be used for emergency planning/response and mitigation work, particularly in the CPUC-designated high fire-threat districts (HFTDs) of California. GIS is the preferred platform for data sharing among the utility companies and agencies.

Inspections provide increased communication and education between regulators and providers before an incident occurs. The primary responsibility of inspections of all components of electrical systems for safety and reliability is with the utility provider per General Order 95 Rule 31.2 and General Order 165. Additionally, Federal and State agencies may do spot checks and hazard notifications as issues arise and staff are available. Ultimately, it is the responsibility of each utility provider to inspect all components of their systems.

Figure 1: Service areas of California investor-owned utilities (map revised in 2020 by CAL FIRE Utility Fire Mitigation GIS staff)

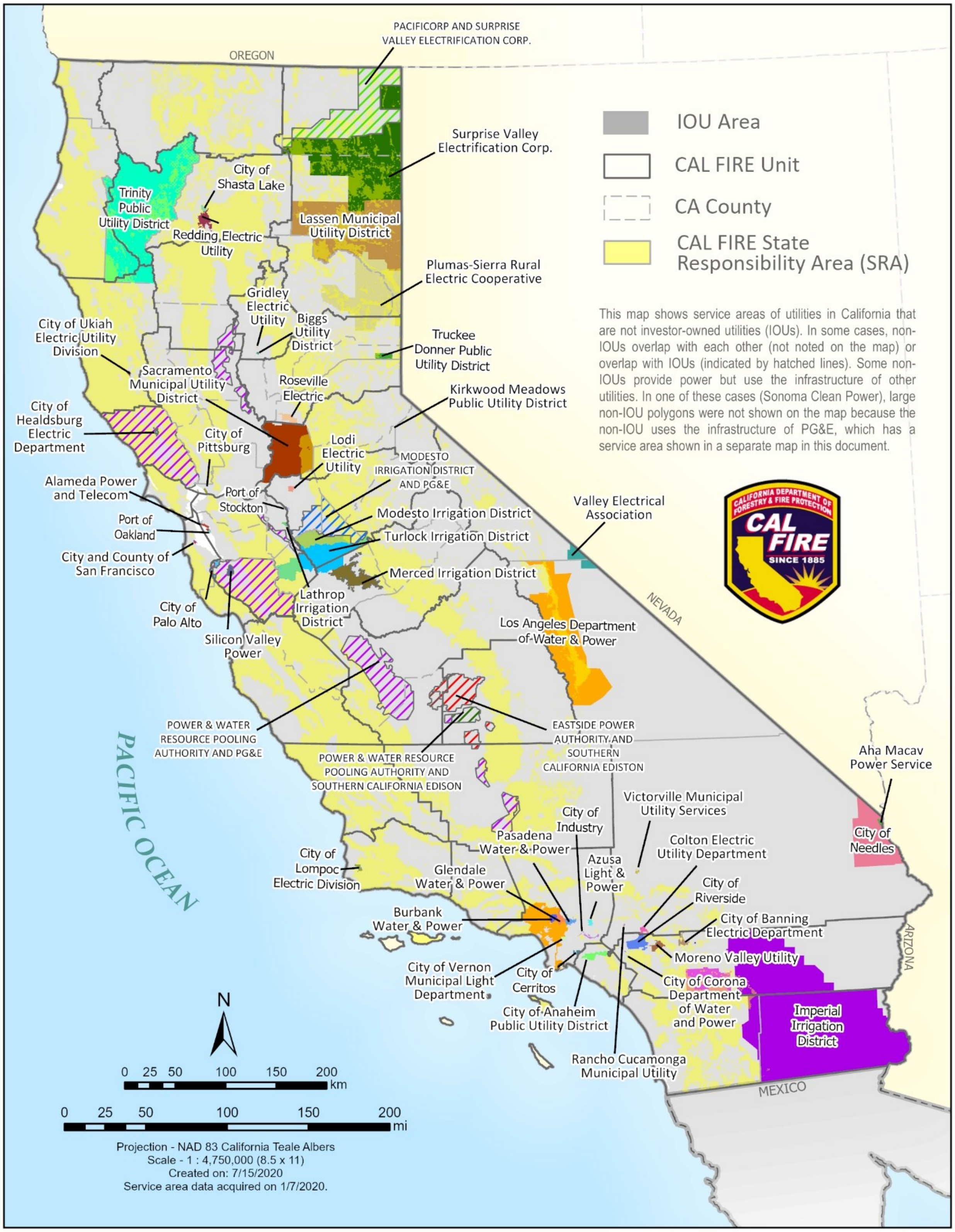


Figure 2: Service areas of California utility companies owned by municipalities or cooperatives (map revised in 2020 by CAL FIRE Utility Fire Mitigation GIS staff)

Figure 3: CAL FIRE regions and units

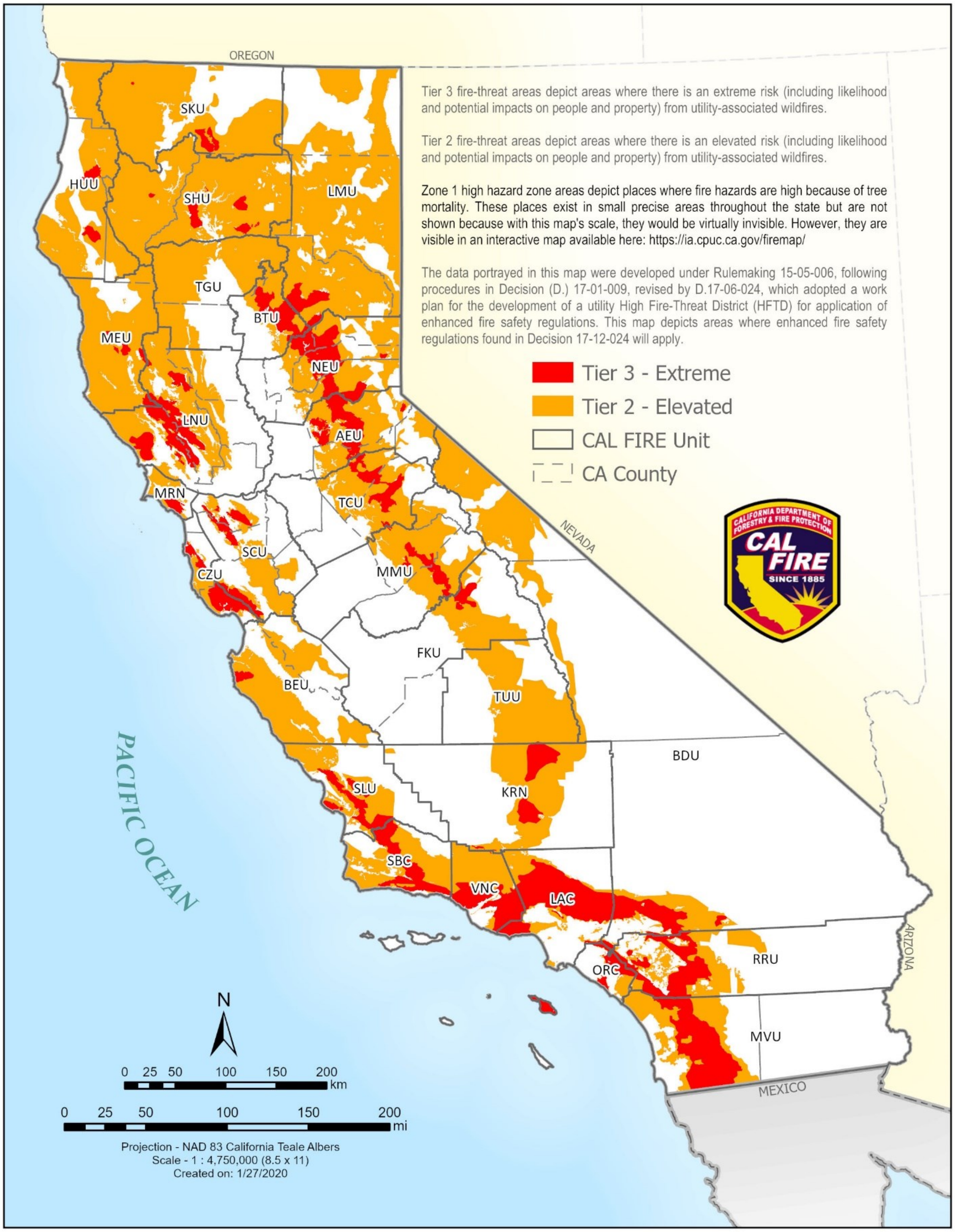


Figure 4: CPUC fire-threat map showing High Fire-Threat Districts (HFTDs) Tier 2 (Elevated) and Tier 3 (Extreme). An interactive version of this map with downloadable data is [located here](#).

Electric Power System

Introduction
Electricity differs from other commercial products, as once it is generated it is immediately consumed. However, there are similarities between it and other manufactured goods. First, a factory is required for production. For electricity, this is the generating plant. Second, the product must be transported in bulk to a distribution center. This is accomplished by use of high-voltage transmission lines. Lastly, from the distribution center, electricity is delivered to the customer over distribution lines. Figure 5 below illustrates a typical transmission distribution system.

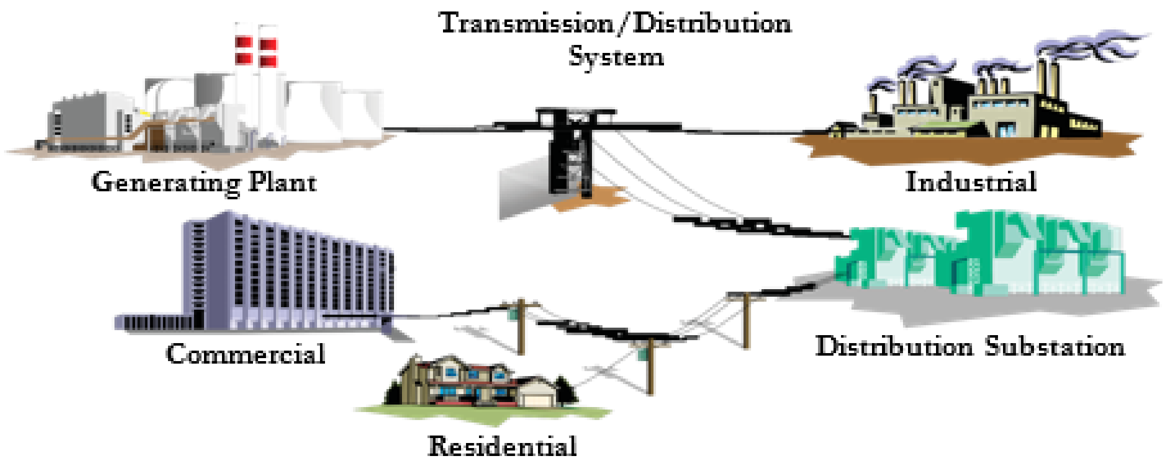


Figure 5: Electrical Power System: Electricity is generated in a plant and travels through high voltage transmission lines to distribution substation(s) and then to the final customer through smaller voltage distribution lines.

Generation
Electricity generation is the process of generating electrical power from a source at a generation plant. According to the California Energy Commission, the total 2018, in-state California electric generation in gigawatt hours came from the following sources: natural gas (46.5%), solar (14%), hydro (13.5%), nuclear (9.4%), wind (7.2%), geothermal (5.9%), biomass (3.0%), and other (0.4%). Source: [California Energy Commission Generation Source]

Subsequent portions of this Guide will discuss kilovolts (kV). A kV is a unit of potential equal to a thousand volts. A unit of potential is a measure of the potential energy of a unit charge at a given point in a circuit relative to a reference point (ground).

Transmission System
After being generated, electricity is transmitted over transmission lines to centrally located transmission and distribution substations. The transmission voltages in common use range from 36 kV to 500 kV.

Distribution System

Distribution systems commonly carry more non-exempt hardware (clearance required) and are usually fed from a substation supplied by a transmission system. At the top of the pole of a distribution circuit, there are primary wires that supply transformers at voltages from 2.4 kV to 35 kV. Transformers then convert the higher voltage electricity carried by primary wires and lowers the voltage for use by customers. Powerlines less than 750 volts must be maintained to avoid strain and abrasion. When the power passes through the transformer it is transferred to the secondary wire which runs below the transformer level of the pole. Secondary voltages normally supplied to customers range from 120 volts to 480 volts. Typically, the utility distribution system stops at its connection with a building, which occurs at a structure known as a weather-head or periscope. Telephone and cable wires are typically attached to distribution systems and are usually the lowest wires on the power pole (see Figure 6).

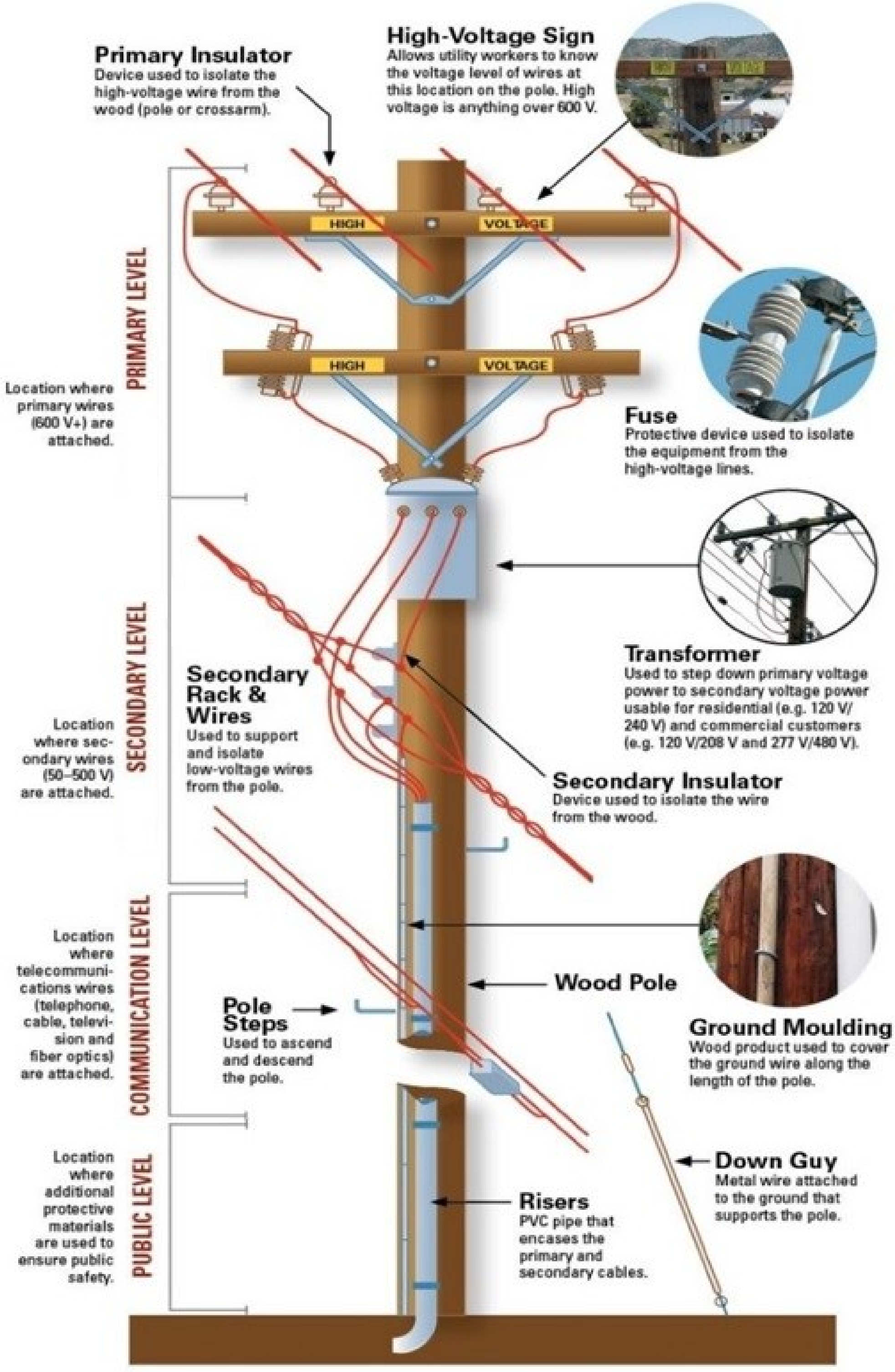


Figure 6: Distribution system: Different levels of electricity (Primary, Secondary, Communication lines) working from the top to the bottom of a distribution power pole

Fire Hazard

Electrical power presents a specific hazard that results in mutual concern from electric utilities and local, state and federal fire protection agencies. The same weather conditions that contribute to power line faults also lead and contribute to the rapid spread of wildfire. High wind is the most critical of these weather factors and is commonly accompanied by high temperatures, low fuel moistures, and low humidity.

Fire Hardening

Among other things, the SB 901 WMPs are required to address increasing the fire safety of electric utilities by "fire hardening" electrical systems both transmission and distribution.

Table 1: Some examples of fire hardening actions for specific electrical distribution components

Distribution/Transmission Component	Fire Hardening Actions
Conductors	• Implement undergrounding where feasible to avoid foreign object arcing. • Covered conductors to eliminate line slap arcing and light vegetation contact. • Aluminum conductor steel reinforced (ACSR) wire
Hardware	• Use exempt hardware per CCR Title 14 Section 1255. • Monitor hardware such as line sensors, ground-fault indicators, fast operating protecting relays, and disabling reclosers.
Poles/Towers	• Use alternative materials such as composite, steel, concrete, or fire-resistive protection on wood poles. Unprotected burnt wood poles cause escape routes to be blocked and additional system damage from fire.

Special Concerns

Introduction

Legal considerations aside, special circumstances can exist that require additional hazard reduction measures to prevent fires or the liability that might arise from them.

Animals

Large birds are a common hazard that create the need for special measures because they frequently use poles or towers as roosting places. Several fire prevention problems arise from this situation. Example: bird droppings build up on insulators to the extent that the potential exists for a flashover between conductors and the cross-arm on a pole or tower. This situation can cause a line fault and the potential for glowing debris to fall from poles to the ground. Example: when a bird takes-off or lands, the wings of a bird can touch two conductors simultaneously and create a short-circuit. This situation can cause the bird to fall to the ground and ignite dry vegetation below the conductor. When electrocuted large dead birds (e.g., birds of prey like raptors) are repeatedly discovered below the same poles or towers, the ground around the poles or towers should be cleared of all vegetation as a fire prevention measure because such poles or towers may continue to attract large birds. When this situation exists, the utility provider for the service area affected must be notified immediately so hazardous conditions can be mitigated (Form LE-38a for CAL FIRE or other agency specific form). Reduced risk for these situations may also be remedied with the installation of raptor construction designed to discourage utility infrastructure use by raptors and other animals (see pages 123-127).

Similar problems exist involving other animals causing a conductive path with transformers or other electrical line equipment. Some utilities use a plastic wildlife protection boot over one bushing of a transformer to prevent birds and animals from causing a direct short-circuit between the transformer bushings. An advisory notification (e.g., CAL FIRE LE-38a or other agency specific form) should be written when these conditions are found.

Damaged Equipment

Other conditions that may lead to potential fire problems are damaged hardware, damaged insulators, weather-damaged poles and broken strands on conductors. Porcelain insulators will allow a flash-over if they lose too much of the skirt. Broken cross-arms, damaged poles or bent brackets and braces can allow conductors to touch the ground or contact each other. These situations, if not corrected, can create a wildfire hazard where one did not previously exist.
To avoid potential wildfire hazards and other problems, damaged equipment should be repaired as reasonably possible. When a hazardous damaged equipment situation exists, the utility provider servicing the area where it is located must be notified immediately so hazardous conditions can be mitigated.

High Hazard Areas

Conformance to regulations does not mitigate all risk, situations exist in which the minimum legal clearance may be inadequate. Example: localized high or turbulent winds found in canyons or extremely high local air temperatures in low elevation canyons. The CPUC High Fire Threat District map shows high hazard areas, see figure 4.

Tree Connections

Standard unprotected conductors (for primary distribution lines) and self-supporting aerial cable can only be attached to trees in accordance with CCR Title 14, Sections 1257 and 1258. However, in no case are conductors of any kind to be mounted to snags or dead trees.

Training

This Guide is to be used as a reference for personnel already familiar with the subject areas it covers. It is also to be used as the base level of knowledge necessary to perform adequate, accurate and complete inspections, which require that personnel using this Guide be properly trained on the application of its contents.

POWER LINE INSPECTION PROCEDURES

The table of contents entries below are hyperlinked to their correlating sections in the document. Clicking on an entry will take you to its section.

Introduction

Electric utilities have a responsibility for inspection of power lines, while regulatory and fire protection agencies have a responsibility to enforce statutory and regulatory requirements. Therefore, the reason and purpose of their inspections are different. Although joint inspections are desirable and helpful, they are often not practical.

Utilities have an operational and management responsibility for inspecting their lines. They must determine what work needs to be done to comply with laws and use permits, prevent fires and avoid interruption of customer service. They also need to know, after the work is assigned, whether it has been completed and to what standard(s).

The regulatory and fire protection agencies' inspection responsibilities are primarily enforcement related for purposes of identifying compliance and potential fire hazards. They should make inspections (spot checks) of as small or large an area as necessary (seldom a complete inspection of an entire circuit) to evaluate electric utilities' compliance with statutes, regulations and use permits. These inspections should normally be done in late spring or early summer, but may occur at any time. Regulatory or fire protection agencies should notify utilities in writing where potential fire hazards or violations are identified.

Maintenance of powerlines and compliance with statutory and regulatory requirements, as well as, correction of identified hazards and mitigation of violations are the responsibility of the utilities. Much of the clearance work is done by contractors; however, the utility itself is responsible for directing these contractors. Neither contractors nor utility company employees should pass by an obvious violation or other problems because it is not on their assigned work list. Also, regulatory and fire protection agency personnel should never ignore an observed violation or piece of broken or damaged equipment. Violations, hazards, or potential hazards should immediately be reported to utilities in writing, so they can be promptly mitigated.

CAL FIRE, the United States Forest Service, the U.S. Bureau of Land Management, other fire protection agencies and, the CPUC may initiate criminal, civil, or administrative processes to educate and encourage compliance with laws and ordinances. These agencies also may process civil actions for collection of fire suppression costs and damage to their resources.

Utility Company Inspections

The responsibility for inspection of power lines for compliance with statutes, regulations and use permits rests exclusively with utilities.

The most common method of power line inspection is visual and is conducted by ground or air. These methods of inspection can accurately determine whether required clearances exist, structures need repair, etc.

Infrared (IR) scans can be used to detect components with thermal anomalies. Improper or loose connections as well as most other incipient deterioration create electrical resistance and therefore heat. Heat often cannot be detected visually but shows up clearly during an IR scan.

In terms of exposure, there are 5 to 10 times as many miles of distribution lines than transmission lines. Fire protection agency and utility provider statistics show that more fires start from distribution lines than from transmission lines. Transmission lines do pose a high fire risk and must be inspected properly; however, distribution circuits commonly carry more non-exempt hardware (clearance required), are near human populations and property, and are built with less conductor clearance than are transmission lines.

The frequency of inspection of both transmission and distribution lines depends on various factors including, but not limited to, the type and growth rate of vegetation, accessibility to fire protection agencies, frequency of strong or gusty winds or fire history, as well as government regulations.

Fire Protection Agency Inspections

Fire protection agencies are charged with the responsibility of protecting the public from loss of life, property and natural resources by fire. Fire protection agencies are also charged with enforcing forest and fire laws, statutes, regulations and use permits. To accomplish these missions, they inspect power lines to prevent wildfires. Fire protection agency inspections do not relieve utilities (corporations, public utilities and cooperatives) of the responsibility of inspecting their own power line facilities and powerlines. Fire protection agencies should make known to utilities those violations and hazards noted during their inspections. Fire protection agency personnel will seldom make a complete inspection of an entire circuit. Their procedures may include spot inspections of individual poles, towers, spans, or short segments of circuits, general surveys (usually by air), compliance checks following prior notification of violations and detailed inspections of small areas (because of fire or complaint).

Most fire protection agency inspections are adequately conducted by visual inspection. Inspectors should be equipped with such aids as binoculars, camera/cell phone, and the latest copy of this field guide. **Because of the danger of electrocution, fire agency personnel are NOT to attempt to physically or mechanically measure conductor clearances. Visual estimation is adequate.**

If fire protection agency personnel notice conditions on power lines that are not violations of fire laws or regulations, but which may cause an electric fault, a hazard to linemen, a break in customer service, etc., such items should be noted and reported to the appropriate utility.

PRC 4119 gives CAL FIRE the authority to enforce California's forest and fire laws and authorizes the Department or authorized agents to inspect all properties, except a dwelling's interior, to ascertain compliance with state forest and fire laws, regulations or use permits.

To perform the inspection successfully, the inspector should have the following specific tools:

A. Agency uniform and appropriate identification.
B. A method to record hazards, risks, and locations. Sketched maps and GIS data aid in future inspections or firefighting operations.
C. Copy of the latest version of the Power Line Fire Prevention Field Guide
D. Binoculars, camera and circuit maps if available.

After completing an inspection, the inspector should note all violations or identified fire hazards, in writing, on an agency approved fire hazard notice. Notification should be made to the responsible utilities as soon as practical for immediate mitigation.

Follow-up inspections are necessary for effective compliance. If the issuance of a citation is necessary, fire protection agencies will follow their specific protocol.

Joint Inspections

Joint inspections (involving fire protection agency staff and utility staff) are for educating both fire protection agencies and electric utility personnel about possible violations and other power line problems. Joint inspections are not always possible because of time commitments or agency policy. They are, however, encouraged to the extent feasible, as they provide an excellent opportunity for mutual training, understanding and trust. Usually the most productive form of joint inspection is the quick general survey of a complete circuit from either the ground or air. Joint inspections should be documented.

Ground Inspections

Ground inspections may be made either in a motor vehicle or on foot. In either case, they are most efficiently performed by two-person teams. When inspecting from a vehicle, one team member should devote their entire attention to driving while the other observes the power line. The speed of the vehicle should be that needed for good observation with careful attention to not disrupting the natural flow of traffic and public safety.

Power lines often do not follow roads or even off-road routes. Therefore, inspections must sometimes be done on foot. More remote power line segments often contain the greatest number of hazards and/or violations. For efficiency, one person should walk the line while the other drives to a point where the line again crosses a road. During this time, it is critical that communication is maintained between the team members. If the line crosses the road and again goes cross-country, the team members can switch roles.

Aerial Inspections

Aerial inspections are an excellent means of covering a lot of territory quickly. Helicopters may be used for power line inspections. Their maneuverability and ability to fly slowly and to hover makes them ideal for this purpose. Cost per flight hour is, however, from two to eight times more than that of a comparably sized fixed-wing aircraft. Cost must be weighed in respect to the thoroughness of inspection needs. It has been demonstrated that with proper planning, preparation, training (of both pilot and observer) and experience, an adequate job of power line inspection can be accomplished from the air using either helicopters or fixed-wing aircraft. Results of aerial inspections should be ground-checked until both pilot and observer have accumulated experience.

Aerial inspections are particularly effective at spotting pole or tower clearances and leaning or dead trees that are not immediately adjacent to the line and the larger pieces of hardware requiring pole or tower clearance. A skilled observer can do many phases of power line inspection equally well from the air or the ground. However, from the air, it is rather difficult to identify small items of hardware, conductor clearances or less obvious tree defects. Some utilities are using un-manned aerial vehicles as well as remote sensing capabilities such as infrared and light detection and ranging (LIDAR).

Recording Inspections

Results of any fire agency inspection where violations or hazards are identified should be properly recorded. Each agency has its own forms and procedures for this purpose. Fire origin and cause investigations will be recorded on agency-specific forms. In California, agency-specific forms are used by CAL FIRE, the USFS, and the BLM. CAL FIRE uses the California Fire Safety Inspection Report LE–38a form (see Figure 7 below). CAL FIRE may also use the Collector for ArcGIS app on mobile devices to record the informational and geospatial data results of power line inspections. Regardless of the format of a fire safety inspection report, a copy should be sent or given to the electric utility owning the infrastructure inspected. Reports should be specific enough for the utility to act on their findings and for the courts to relate them to complaints or other legal actions in the event such actions are filed.

State of California
Department of Forestry and Fire Protection
CAL FIRE
LE-38a (Rev. 04/16)

Fire Safety Inspection Legal Notice

Inspectee	Name:							Phone Number:			
	Address:										
	City:							State:		Zip Code:	
	DOB:		DL/ID Number:		HT:		WT:		Hair:		Eyes:
Inspection Information	Address:										
	City:							State:		Zip Code:	
	Latitude:		Longitude:					Re-inspection Date:			
Number Inspected	Structures:		Camp Fire:		Incinerator:		Fire Tools:		Mech. Equipment:		
	Power line:		Waste Disp:		Open Burn:		Other:				

This is legal Notice of Fire Hazard Violations (If Noted Below)
Public Resource Codes (PRC) and Health and Safety Codes (H&S) (Check all that apply)

☐ PRC 4292 - Powerline hazard reduction	☐ PRC 4425 - Violation of terms of permit	☐ PRC 4442 (.5) (.6) - Spark arrester required
☐ PRC 4293 - Powerline clearance required	☐ PRC 4427- Required clearance & tools for mach.	☐ H&S 12671 - Possession of unregistered fireworks
☐ PRC 4296.5 - Railroad vegetation clearance	☐ PRC 4428 - Fire Toolbox – Industrial operation	☐ H&S 13000 - Allowing a fire to escape
☐ PRC 4421 - Setting fire on lands of another	☐ PRC 4431 - Operations of gas powered tools req.	☐ H&S 13001 - Cause a fire - careless or negligent act
☐ PRC 4422 - Allowing fire to burn uncontrolled	☐ PRC 4432 - Neglecting a campfire	☐ H&S 13002 - Throwing smoking or flaming material
☐ PRC 4423 - Burning without a permit	☐ PRC 4433/34 - Campfire permit required/Escape	☐ H&S 13004 - Pump reqs. for agriculture activities
☐ PRC 4423.5 - Burning during a burning suspension	☐ PRC 4435 - Fire originating from a device	☐ H&S 41800 - Illegal burning of waste products

Other:

Comments

Incident Number:		Incident Name:		Date:	
Inspector Name:		Inspector Signature:		Phone Number:	
Inspectee Signature:			Date:		

Form LE-38a (Rev. 04/16) (Original to Fire Prevention, Copy to Inspectee)

Figure 7: CAL FIRE Form LE-38a: Fire Safety Inspection Legal Notice

Location Identification

Fire protection agencies and electric utilities may have different systems of position or location identification (i.e. GPS vs Pole Numbers). For communications (including inspection reports), inquiries regarding problems, etc. to be meaningful, it is essential that both groups have at least a working knowledge of the other's system. Local joint training sessions should be utilized to acquaint personnel with these systems.

Most fire protection agencies use latitude/longitude (lat/long) coordinates to present spatial information on the surface of the Earth. Spatial data can be shared in a variety of formats with KMZs, shapefiles and geodatabase (GDBs) being the most common with online web services (e.g., ArcGIS Online) increasingly becoming a standard. These data formats can be consumed in geographic information systems (GIS) software (e.g. Google Earth, ArcGIS) that accurately projects latitude/longitude coordinates on the Earth for visual interpretation or analysis.

The electric utilities (with some variation between systems) generally identify locations by circuit name, pole, tower or hardware number. Transmission lines are usually named, and each pole or tower is numbered. One common system of such numbering is a fraction, the top number being the mile from the point of beginning and the bottom number being the number of the pole or tower within that mile. Customized numbering systems used by a utility should be learned by fire agency personnel. Depending on the utility, distribution circuits may be numbered, named or both. Some utilities also number individual poles as well as just identify Subject Poles. Also, items of major equipment (e.g. automatic reclosers, switches, disconnects, etc.) are numbered. Poles without pole or equipment numbers must be located by reference to existing pole or equipment numbers (e.g., "fourth pole north of disconnect 6859" or "second pole west of pole 1892096E"). Figures 8 and 9 (see below) show examples of pole identification numbering formats used by SCE and PG&E.

Per General Order (GO) 95, poles and towers carrying circuits of over 750 volts must be marked as "High Voltage." Therefore, any pole or tower so marked can be identified as supporting either a primary distribution or a transmission line. The absence of such marking should not lead one to assume that only low voltage (secondary distribution) is present. Nearby poles on the same circuit should be checked as the marking may have fallen off individual poles.

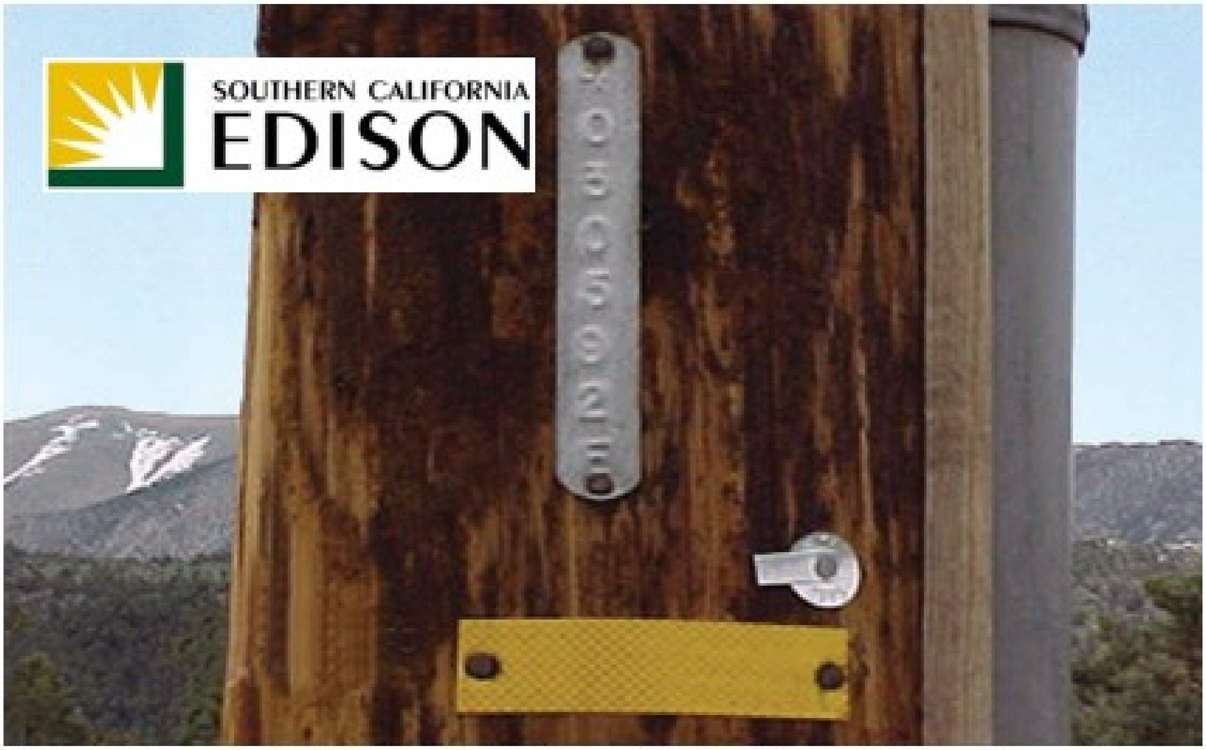


Figure 8: Examples of pole identification (contact local utility provider for utility specific markings).

Figure 9: Examples of pole identification (contact local utility for provider utility specific markings).

EXEMPTIONS, STATUTES, REGULATIONS AND STATE LAWS

The table of contents entries below are hyperlinked to their correlating sections in the document. Clicking on an entry will take you to its section.

SRA Utility Pole/Tower Vegetation Clearance Law and Exemptions

Pole/Tower Clearances

In the CAL FIRE State Responsibility Area (SRA), the requirement for clearances around poles and towers is contained in Public Resources Code (PRC) 4292. This section requires clearing of flammable fuels for a minimum 10-foot radius from the outer circumference of certain poles and towers (non-exempt or subject poles and towers). The distances for clearance requirements must be measured horizontally, not along the surface of the sloping ground.

Title 14, Section 1255 exempts specific poles or towers from needing PRC 4292 vegetation clearance where the conductors are continuous, or if not continuous, where they are joined by approved/exempt splices or connectors. Section 1255 also outlines hardware that has less fire risk and determined exempt from PRC 4292 as well. The remaining exemptions in Section 1255 are related to the maintenance practices and vegetation growing around poles or towers. The exemptions cover vegetation that is not flammable and is maintained for the specific purpose of soil erosion or nonflammable ground cover. This is not intended as a loophole. The key words are "specific purpose," and they require a positive demonstration of this purpose to qualify.

Conductor Clearance Law

Any electrical utilities in mountainous, grass, brush, or forest-covered lands must adhere to the requirements for vegetation clearances around electrical conductors that are contained in PRC 4293. This section requires clearance of all vegetation within a specific radial distance from conductors. Radial distances in which vegetation must be cleared are based on voltages carried by conductors and are listed below with their associated voltages:

- 4 feet for voltages between 2,400 volts and 72,000 volts
- 6 feet for voltages between 72,000 volts and 110,000 volts
- 10 feet for voltages over 110,000 volts

In addition, PRC 4293 requires the removal or trimming of trees or portions of trees that lean toward power lines or that are dead, decadent, rotten, decayed or diseased **and** may fall into or onto lines. This requirement is independent of the clearances distances identified above and in some cases, may even extend beyond the easements for the utility.

Relative to the distances in PRC 4293, some electrical company policies require considerably more clearance as a rule or in special situations, such as unusually long spans in high wind areas. This is especially true where lines are passing through areas of rapidly growing vegetation.

In many cases, fire agencies can consider utility rights-of-way or easements as fire breaks. On these fire breaks, the stacking or accumulation of debris resulting from tree trimming or removal operations should be avoided. When these conditions exist, debris should be chipped and scattered to prevent compromising the fire breaks.

Title 14, Section 1257 exempts conductors from needing PRC 4293 vegetation clearance where certain types of conductors or exempt trees exist.

PRC 4292 states that any line used exclusively as a communications circuit—and so classed by the CPUC—is exempt from the pole or tower clearance requirement. Various lines used largely but not exclusively for communication are not exempt. For instance, railroad circuits are used primarily for communication purposes but also provide power (e.g., more than 750 volts to operate track switches) and thus are not exempt.

PRC 4292 also authorizes the Director of CAL FIRE or the agency that has primary fire protection responsibilities for an area to make exceptions based upon the specific circumstances involved. Exemptions are contained in CCR Title 14, Section 1255 concerning installed hardware and ground cover.

PRC 4293
Powerline conductor clearance

PRC 4295 recognizes private property rights by not requiring trespass if that is the only way in which clearance requirements can be maintained. It is not, however, intended as a loophole. Utilities are expected to make a reasonable effort to secure permission to undertake clearances, and if unsuccessful, they are expected to report their access problems to the responsible fire protection agency. The fire protection agency can then attempt to persuade the property owner to allow clearing.

PRC 4296 exempts lines carrying voltages up to 750 volts. **It has been found, however, that such lines, which are not insulated, can start fires. It is therefore considered good practice to maintain some clearance on these lines.**

Exemption Procedure for Hardware

The CAL FIRE Procedure for qualifying electrical equipment and devices for exemption from PRC 4292 in the SRA is outlined in CCR Title 14, Section 1255.

The utility or hardware vendor will submit all exemption requests to the CAL FIRE Wildfire Planning and Engineering Division's Utility Fire Mitigation Program and will include at least the following:

- Written request and pre-meeting invitation for temporary exemption
- Sample Product
- Engineered product drawing and installation instructions
- Test results
- Tests shall be video recorded in 1080p high resolution color and infrared.
- Electronic photographs and descriptions of equipment/devices tested
- Descriptions of testing procedures (i.e., ANSI Standard C37.40 – 1981)
- Professional third-party Electrical Engineer conclusions

Within 60 days after receiving a request for exemption, CAL FIRE will forward written notification to the requesting utility. Notification will consist of at least the following:

- Approval or denial of a Temporary (36-Month) Exemption
- Justification for the determination

Prior to obtaining an exemption from PRC 4292 from CAL FIRE, equipment and devices will be tested to ensure compliance with the test procedures outlined in the standards in this Guide, which are listed below:

- The CAL FIRE Wildland Fire Prevention Engineering/Utility Fire Mitigation Program will be notified 30 days prior to an exemption test.
- The electrical tests for determining compliance will be conducted under the direction of a third-party Electrical Engineer using test equipment capable of making and breaking preset loads. The current, voltage, and starting and ending times shall be graphically recorded and become a permanent part of the documentation of the request for exemption.
- Tests will be conducted utilizing a fuel bed representative of flammable vegetation (dead, dried grass or equivalent) with a fine fuel moisture of 5% at a minimum temperature of 80° Fahrenheit and an accompanying wind speed of 10 MPH or more.
- All equipment installed on lines shall be operated within the maximum manufacturer's duty rating of the equipment or device.
- While undergoing testing, equipment shall be installed according to manufacturer's specifications.
- Enclosed devices (i.e., reclosers, sectionalizers, autotransformers, non-expulsion devices etc.) shall be designed so no external arcs/sparks or expelled hot particles will be generated during the operation.
- Open type or fixed devices (i.e., air switches, open link fuses, connectors, lightning arresters, manual bypass switches and disconnects) shall interrupt line current and short-circuit current within the design range without creating arcs/sparks or hot particles that would ignite flammable vegetation.

- The equipment or overhead device, when installed according to the manufacturers' recommendations, must be fire safe, by test, where exposed/anticipated electrical arcs or hot material could be generated.
- Overhead line equipment and devices that may generate exposed electrical arcs, sparks or hot material during their operation shall be designed to limit any such arcs, sparks or hot materials sufficiently to prevent the ignition of flammable vegetation
- Igniting any portion of the test bed will disqualify the device when testing is conducted according to the standards described above. In addition, the presence of sparks and hot material emitted during the testing may disqualify the device from passing at the discretion of CAL FIRE staff.

Table 2 on Page 25 outlines power line hardware that has a temporary or permanent exemption letter from the CAL FIRE Director as allowed in CCR Title 14, Section 1255. The exemption letters were granted after consideration of the testing requirements described on pages 22-23 of this Guide.

CAL FIRE's approval for exemption from PRC4292 pole clearance in no way gives permission or authorizes the use of any CAL FIRE logo or symbol for the purpose of any advertising, promotion, or marketing, related to exempted products or their business. CAL FIRE and its logos and symbols are registered service and trademarks and may not be used for the purposes of advertising, promotion, or marketing, or used to expressly or implicitly suggest CAL FIRE endorses said product.

Table 2 Exempt Equipment Table

Exempt Equipment Table

Hardware Name/Description	Vendor or CCR Applicable to Exemption	Temporary Exemption Date	Permanent Exemption Date	Pages
Fire Protection Disconnector (used with Hubbell Arrestor)	Hubbell	4/23/2020	-	77
Fuse Saver	Siemens	4/16/2020		78
Linescope for use on circuits up to 115 Kv	Cleaveland Price	12/1/2018	-	79
Clampstar Shunt	Classic Connectors	6/23/2020	-	79
TripSaver II Cutout Mounted Recloser	S&C Electric	1/14/2019	-	80
Current Limiting Non-Expulsion Fuse	Title 14 CCR 1255 (10)	-	5/8/1989	81-82
Liquid Filled Fuse	Title 14 CCR 1255 (8)	-	5/11/1983	83-84
Energy Limiting Fuse (ELF) – Family of Fuses	Eaton-Cooper Fuses	4/26/2004	6/3/2005	85
SMU-20 Fuses **Type-CMU Fuse** **Type-DBU Fuse**	S&C Electric/ Westinghouse/Eaton-Cooper	8/18/1994	-	86
Fault Tamer Fuses	S&C Electric	-	5/8/1989	87
600 AMP Air Switch (does not apply in SDGE service territory)	KPF	8/18/1994	-	88-89
Underarm Side Break Switch 600 & 900 Amp	Eaton-Cooper	6/15/1999	-	90
S&C Omni-Rupter Side Break Switch	S&C Electric	1/4/2000	-	91-93
Scada-Mate Switch	S&C Electric	6/15/1999	-	94
27 kV Line Boss Side Break Switch	Inertia	8/1/2003	-	95
In-Line and Solid Blade Disconnects (exempt only with reclosers, Sectionalizers, and Voltage Regulators)	Title 14 CCR 1255 (7)	-	5/11/1983	96
Sectionalizer	Title 14 CCR 1255 (8)	-	5/11/1983	97

Hardware Name/Description	Vendor or CCR Applicable to Exemption	Temporary Exemption Date	Permanent Exemption Date	Pages
Parallel Groove Connector/GA9000	Title 14 CCR 1255 (3)	-	5/11/1983	101-102
Hot Tap Clamps (some hot tap clamps are Non-Exempt)	Utilco	3/29/1995	-	103
Piercing Hot Tap Clamp	Title 14 CCR 1255 (5)	-	5/11/1983	104
Tree Wire Tie Wire	Title 14 CCR 1255 (5)	-	5/11/1983	105
Idle Split Bolt Connectors (only exempt when idle on the line)	Title 14 CCR 1255 (1)	-	5/11/1983	106
Wedge Connectors	Title 14 CCR 1255 (6)	-	5/11/1983	107
Compression Connectors	Title 14 CCR 1255 (1)	-	5/11/1983	108
Bolted Flat Plate Connector (installed with not less than two bolts)	Title 14 CCR 1255 (6)	-	5/11/1983	109
Automatic Dead-End	Title 14 CCR 1255 (2)	-	1/1/1977	110
Splices (compressed, automatic, and mechanical splices)	Title 14 CCR 1255 (1) (2)	-	1/1/1977	111-112
15kV & 25kV Type 3EK4 surge arresters with (APS) and visible fault indicator	Siemens	9/10/2014	8/25/2017	113
Surge Arrestor with SPU rated 10kA IEC Class I & II 44kV and below	ABB, Inc.	4/10/2017	9/10/2018	114
Sealed & Liquid Filled Reclosers	Title 14 CCR 1255 (8)	-	5/11/1983	115

Statute and Regulation Language

Introduction
This Guide has been designed to present only those laws and regulations, or portions thereof, which pertain directly to power line fire prevention in California. As such, this document should only be used as a quick reference. For full and current text, meaning and proper context of laws and regulations, reference should be made to applicable codes, manuals, directives, websites, etc.

Quick Reference to Power Line Statutes and Regulations
See the table of contents at the beginning of the document or this section to quickly find which pages contain various laws associated with power line fire prevention.

Public Resources Code

714: Organization and General Powers

(a) Providing fire protection, fire prevention, pest control, and forest and range protection and enhancement implements and apparatus as necessary.
(b) Maintaining an integrated staff to accomplish fire protection, fire prevention, pest control, and forest and range protection and enhancement activities as needed.
(c) Establishing and maintaining facilities for the performance of fire protection, fire prevention, pest control, and forest and range protection and enhancement activities.
(d) Enforcing forest and fire laws, the Z'berg-Nejedly Forest Practice Act of 1973 (Chapter 8 (commencing with Section 4511), Part 2, Division 4), and other laws specified in Division 4 (commencing with Section 4001).

4021: Penalty

Except as otherwise provided, the willful or negligent commission of any of the acts prohibited or the omission of any of the acts required by Chapter 2 (commencing with Section 4251) to Chapter 6 (commencing with Section 4411), inclusive, of Part 2 of this division is a misdemeanor.

4101: "Person" Defined

"Person" includes any agency of the state, county, city, district or other local public agency and any individual, firm, association, partnership, business trust, corporation or company.

Note: This definition includes publicly-owned utilities (e.g. REA's, SMUD, L.A. Dept. of Water and Power, etc.). It does not include federal agencies (e.g. Bureau of Reclamation, U.S. Army Corps of Engineers, etc.).

4117: Local Ordinance

Any county, city, or district may adopt ordinances, rules or regulations to provide fire prevention regulations that are necessary to meet local conditions of weather, vegetation, or other fire hazards. Such ordinances, rules or regulations may be more restrictive than state statutes to meet local fire conditions.

4119: Enforcing State Forest and Fire Laws Duty of State Officer

The Director of Forestry and Fire Protection, or his duly authorized agent, shall enforce the state forest and fire laws. He may inspect all properties, except the interior of dwellings, subject to the state forest and fire laws, for the purpose of ascertaining compliance with such laws.

Note: By interagency agreement, many employees of the U.S. Forest Service, Bureau of Land Management, National Park Service and certain county fire departments are "duly authorized agents" of the Director of Forestry and Fire Protection.

4125: Classification of Lands as State Responsibility Areas for Fire Protection

The board shall classify all lands within the state, without regard to any classification of lands made by or for any federal agency or purpose, for the purpose of determining areas in which the financial responsibility of the state. The prevention and suppression of fires in all areas which are not so classified is primarily the responsibility of local or federal agencies, as the case may be.

Note: Specific Regulations under this Section can be found in Title 14 Sections 1220-1220.5, California Administrative Code.

4126: State Responsibility Areas: Lands Included

The board shall include within state responsibility areas all the following lands:

a) Lands covered wholly or in part by forests or by trees producing or capable of producing forest products.
b) Lands covered wholly or in part by timber, brush, undergrowth or grass, whether of commercial value or not, which protect the soil from excessive erosion, retard runoff of water or accelerate water percolation, if such lands are sources of water which is available for irrigation or for domestic or industrial use.
c) Lands in areas which are principally used or useful for range or forage purposes, which are contiguous to the lands described in subdivisions (a) and (b).

Note: Specific Regulations under this Section can be found in Title 14, Sections 1220-1220.5, California Administrative Code.

4127: State Responsibility Areas: Lands Excluded

a) The board shall not include within this state responsibility areas any of the following lands: Lands owned or controlled by the federal government or any agency of the federal government.
b) Lands within the exterior boundaries of any city.
c) Any other lands within the state which do not come within any of the classes which are described in Section 4126.

Note: Specific Regulations under this Section can be found in Title 14, Sections 1220-1220.5, California Administrative Code.

4128: State Responsibility Area Boundaries

In establishing boundaries of state responsibility areas, the board may, for purposes of administrative convenience, designate roads, pipelines, streams, or other recognizable landmarks as arbitrary boundaries.

4171: Public Nuisances Defined

Any condition endangering public safety by creating a fire hazard and which exists upon any property which is included within any state responsibility area is a public nuisance.

4202: Fire Hazard Severity Zones

The director shall classify lands within state responsibility areas into fire hazard severity zones. Each zone shall embrace relatively homogeneous lands and shall be based on fuel loading, slope, fire weather, and other relevant factors present, including areas where winds have been identified by the department as a major cause of wildfire spread.

4292: Power Line Hazard Reduction

Except as otherwise provided in Section 4296, any person that owns, controls, operates, or maintains any electrical transmission or distribution line upon any mountainous land, or forest- covered land, brush-covered land, or grass-covered land shall, during such times and in such areas as are determined to be necessary by the director or the agency which has primary responsibility for fire protection of such areas, maintain around and adjacent to any pole or tower which supports a switch, fuse, transformer, lightning arrester, line junction, or dead end or corner pole, a firebreak which consists of a clearing of not less than 10 feet in each direction from the outer circumference of such pole or tower. This section does not, however, apply to any line which is used exclusively as telephone, telegraph, telephone or telegraph messenger call, fire or alarm line, or other line which is classed as a communication circuit by the Public Utilities Commission. The director or the agency which has primary fire protection responsibility for the protection of such areas may permit exceptions from the requirements of this section which are based upon the specific circumstances involved.

4293: Power Line Clearance Required

Except as otherwise provided in Sections 4294 to 4296, inclusive, any person that owns, controls, operates, or maintains any electrical transmission or distribution line upon any mountainous land, or in forest-covered land, brush-covered land, or grass-covered land shall, during such times and in such areas as are determined to be necessary by the director or the agency which has primary responsibility for the fire protection of such areas, maintain a clearance of the respective distances which are specified in this section in all directions between all vegetation and all conductors which are carrying electric current:

a) For any line which is operating at 2,400 or more volts, but less than 72,000 volts, four feet.
b) For any line which is operating at 72,000 or more volts, but less than 110,000 volts, six feet.
c) For any line which is operating at 110,000 or more volts, 10 feet.

In every case, such distance shall be sufficiently great to furnish the required clearance at any position of the wire, or conductor when the adjacent air temperature is 120 degrees Fahrenheit, or less. Dead trees, old decadent or rotten trees, trees weakened by decay or disease and trees or portions thereof that are leaning toward the line which may contact the line from the side or may fall on the line shall be felled, cut, or trimmed so as to remove such hazard. The director or the agency which has primary responsibility for the fire protection of such areas may permit exceptions from the requirements of this section which are based upon the specific circumstances involved.

4294: Aerial Cable

A clearing to obtain line clearance is not required if self-supporting aerial cable is used. Forked trees, leaning trees, and any other growth which may fall across the line and break it shall, however, be removed.

4295: Clearance Not Required

A person is not required by Section 4292 or 4293 to maintain any clearing on any land if such person does not have the legal right to maintain such clearing, nor do such sections require any person to enter upon or to damage property which is owned by any other person without the consent of the owner of the property.

4295.5: Right of Entry

(a) Notwithstanding any other law, including Section 4295, any person who owns, controls, operates, or maintains any electrical transmission or distribution line may traverse land as necessary, regardless of land ownership or express permission to traverse land from the landowner, after providing notice and an opportunity to be heard to the landowner, to prune trees to maintain clearances pursuant to Section 4293, and to abate, by pruning or removal, any hazardous, dead, rotten, diseased, or structurally defective live trees. The clearances obtained when the pruning is performed shall be at the full discretion of the person that owns, controls, operates, or maintains any electrical transmission or distribution line, but shall be no less than what is required in Section 4293. This section shall apply to both high fire threat districts, as determined by the California Public Utilities Commission pursuant to its rulemaking authority, and to state responsibility areas.

(b) Nothing in subdivision (a) shall exempt any person who owns, controls, operates, or maintains any electrical transmission or distribution line from liability for damages for the removal of vegetation that is not covered by any easement granted to him or her for the electrical transmission or distribution line.

(Added by Stats. 2018, Ch. 641, Sec. 9. (AB 2911) Effective January 1, 2019.)

4296: Low Voltage Lines

Sections 4292 and 4293 do not apply if the transmission or distribution line voltage is 750 volts or less.

Health and Safety Code

13001: Causing Fire

Misdemeanor. Every person is guilty of a misdemeanor who, through careless or negligent action, throws or places any lighted cigarette, cigar, ashes, or other flaming or glowing substance, or any substance or thing which may cause a fire, in any place where it may directly or indirectly start a fire, or who uses or operates a welding torch, tar pot or any other device which may cause a fire, who does not clear the inflammable material surrounding the operation or take such other reasonable precautions necessary to insure against the starting and spreading of fire.

13007: Liability for Damage

Any person who personally or through another willfully, negligently or in violation of law, sets fire to, allows fire to be set to or allows a fire kindled or attended by him to escape to, the property of another, whether privately or publicly owned, is liable to the owner of such property for any damages to the property caused by the fire

13009: Suppression Cost Collectible

(a) Any person who negligently, or in violation of the law, sets a fire, allows a fire to be set or allows a fire kindled or attended by him to escape onto any forest, range, or non-residential grass-covered land is liable for the expense of fighting the fire and such expense shall be a charge against that person. Such charge shall constitute a debt of such person and is collectible by the person, or by the federal, state, county, public or private agency, incurring such expenses in the same manner as in the case of an obligation under a contract, expressed or implied.
(b) Public agencies participating in fire suppression, rescue or emergency medical services as set forth in subdivision (a) may designate one or more participating agencies to bring an action to recover costs incurred by all of the participating agencies. An agency designated by the other participating agencies to bring an action pursuant to this section shall declare that authorization and its basis in the complaint, and shall itemize in the complaint the total amounts claimed under this section by each represented agency.
(c) Any costs incurred by the Department of Forestry is suppressing any wildland fire originating or spreading from a prescribed burning operation conducted by the department pursuant to a contract entered into pursuant to Article 2 (commencing with Section 4475) of Chapter 7 of Part 2 of Division 4 of the Public Resources Code shall not be collectable from any party to the contract, including any private consultant or contractor who entered into an agreement with that party pursuant to subdivision (d) of Section 4475.5 of that code, as provided in subdivision (a), to the extent that those costs were not incurred as a result of a violation of any provision of the contract.
(d) This section applies to all areas of the state, regardless of whether primarily wildlands, sparsely developed, or urban.

13009.1: Liability of person who negligently sets fire; Burden of proof; Limitation on use of evidence.

(a) Any person (1) who negligently, or in violation of the law, sets a fire, allows a fire to be set or allows a fire kindled by him or her to escape onto any public or private property is liable for both of the following:
    (1) The cost of investigating and making any reports with respect to the fire.
    (2) The costs relating to accounting for that fire and the collection of any funds pursuant to Section 13009, including, but not limited to, the administrative costs of operating a fire suppression cost recovery program.
(b) The liability imposed pursuant to this paragraph is limited to the actual amount expended which is attributable to the fire. In any civil action brought for the recovery of costs provided in this section, the court in its discretion may impose the amount of liability for costs described in subdivision (a).

(c) The burden of proof as to liability shall be on the plaintiff and shall be by a preponderance of the evidence in an action alleging that the defendant is liable for costs pursuant to this section. The burden of proof as to the amount of costs recoverable shall be on the plaintiff and shall be by a preponderance of the evidence in any action brought pursuant to this section.
(d) Any testimony, admission, or any other statement made by the defendant in any proceeding brought pursuant to this section, or any evidence derived from the testimony, admission or other statement, shall not be admitted or otherwise used in any criminal proceeding arising out of the same conduct.
(e) The liability constitutes a debt of that person and is collectible by the person, or by the federal, state, county, public, or private agency, incurring those costs in the same manner as in the case of an obligation under a contract, expressed or implied.
(f) This section applies in all areas of the state, regardless of whether primarily wildlands, sparsely developed, or urban.

13009.5: Charge for use of inmate labor

Where the Department of Forestry and Fire Protection utilizes labor for fighting fires, the charge for their use, for the purpose of Section 13009, shall be set by the Director of Forestry and Fire Protection. In determining the charges, he or she may consider, in addition to costs incurred by the department, the per capita cost to the state of maintaining the inmates.

California Code of Regulations Title 14

1250: Purpose

The purpose of Article 4 is to provide specific exemptions from: electric pole and tower firebreak clearance standards, electric conductor clearance standards and to specify when and where the standards apply.

1251: Definitions

The following definitions apply to this article unless the context requires otherwise:

(a) "Conductor" means connector, a wire or a combination of wires, and/or any other appliance designed and manufactured for use in the transmission and distribution of electrical current.
(b) "Connector" means a device approved for energized electrical connections.
(c) "Duff" means partially decayed leaves, needles, grass or other organic material accumulated on the ground.
(d) "Firebreak" means a natural or artificial barrier usually created by the removal or modification of vegetation and other flammable materials for the purpose of preventing the spread of fire.
(e) "Hot line tap or clamp connector" means a connector designed to be used with a grip-All Clamp stick (Shotgun) for connecting equipment jumper or tap conductors to an energized main line or running conductor.
(f) "Outer Circumference" means the exterior surface of a pole or tree at ground level or a series of straight lines tangent to the exterior of the legs of a tower at ground level.

(g) "Self-supporting aerial cable" means an assembly of abrasion resistant insulated conductors supported by a messenger cable which is normally grounded, designed and manufactured to carry electrical current for installation on overhead pole lines or other similar overhead structures.

(h) "Tree wire" means an insulated conductor covered with a high abrasion resistant, usually non-metallic, outer covering, designed and manufactured to carry electrical current for installation on overhead pole lines or other similar overhead structures.

1252: Areas where PRC 4292, 4293 Apply in State Responsibility Areas.

The Director will apply PRC 4292-4296 in any mountainous land, forest-covered land, brush-covered land or grass-covered land within State Responsibility Area unless specifically exempted by 14 CCR, sections 1255 and 1257.

Note: Authority cited: Sections 4292 and 4293, Public Resources Code. Reference: Sections 4125-4128, 4292, 4293, Public Resources Code.

1252.1: Official Area Maps

The official maps of State Responsibility Areas defined in 14 CCR 1220 are available for viewing and copying during normal business hours at the California Office of The State Fire Marshal, 2251 Harvard St, Sacramento, California, 95815, Suite 400.

When pursuant to PRC 4125-4128, the Board Revises State Responsibility Area boundaries, the Director will forward a legal description of a boundary change(s) to the respective electric utility(s) serving the area(s).

Note: Authority cited: Sections 4292 and 4293, Public Resources Code. Reference: Sections 4125-4128, 4292, 4293, Public Resources Code.

1252.2: Boundary Location - Roads Etc.

Where the boundaries of areas described in 14, CCR 1252, are along roads, highways, streets, railroads, streams, canals or rivers, the actual boundary shall be the center-line of the course of such roads, highways, streets, railroads, streams, canals and rivers.

Note: Authority cited: Sections 4292 and 4293, Public Resources Code. Reference: Sections 4125-4128, 4292, 4293, Public Resources Code.

1253: Time when PRC 4292-4296 Apply

The minimum firebreak and clearance provisions of PRC 4292-4296 are applicable during the declared California Department of Forestry and Fire Protection fire season for a respective county. The Director shall post the declaration on the official Department web site.

Note: Authority sited: Sections 4292-4293, Public Resources Code. Reference: Sections 4125-4128, 4292 and 4293, Public Resources Code.

1254: Minimum Clearance Provisions PRC 4292

The firebreak clearances required by PRC 4292 are applicable within an imaginary cylindrical space surrounding each pole or tower on which a switch, fuse, transformer or lightning arrester is attached and surrounding each dead-end or corner pole, unless such pole or tower is exempt from minimum clearance requirements by provisions of 14, CCR, 1255 or PRC 4296. The radius of the cylindroid is 3.1 m (10 feet) measured horizontally from the outer circumference of the specified pole or tower with height equal to the distance from the intersection of the imaginary vertical exterior surface of the cylindroid with the ground to an intersection with a horizontal plane passing through the highest point at which a conductor is attached to such pole or tower. Flammable vegetation and materials located wholly or partially within the firebreak space shall be treated as follows:

(a) At ground level - remove flammable materials, including but not limited to, ground litter, duff and dead or desiccated vegetation that will allow fire to spread, and;
(b) From 0 - 2.4 m (0-8 feet) above ground level remove flammable trash, debris or other materials, grass, herbaceous and brush vegetation. All limbs and foliage of living trees shall be removed up to a height of 2.4 m (8 feet).
(c) From 2.4 m (8 feet) to horizontal plane of highest point of conductor attachment remove dead, diseased or dying limbs and foliage from living sound trees and any dead, diseased or dying trees in their entirety.

1255: Exemptions to Minimum Clearance Provisions - PRC 4292

The minimum clearance provisions of PRC 4292 are not required around poles and towers, including line junction, corner and dead end poles and towers:

(a) Where all conductors are continuous over or through a pole or tower; or
(b) Where all conductors are not continuous over or through a pole or tower, provided, all conductors and subordinate equipment are of the types listed below and are properly installed and used for the purpose for which they were designed and manufactured;
    (1) Compression connectors.
    (2) Automatic connectors.
    (3) Parallel groove connectors.
    (4) Hot line tap or clamp connectors that were designed to absorb any expansion or contraction by applying spring tension on the main line or running conductor and tap connector.
    (5) Fargo GA 300 series piercing connectors designed and manufactured for use with tree wire.
    (6) Flat plate connectors installed with not less than two bolts.
    (7) Tapered C-shaped member and wedge connectors.
    (8) Solid blade single-phase bypass switches and solid blade single-phase disconnect switches associated with circuit reclosers, sectionalizers and line regulators.
    (9) Equipment that is completely sealed and liquid filled.
    (10) Current limiting, non-expulsion fuses.
(c) On the following areas, if fire will not propagate thereon;
    (1) Fields planted to row crops.
    (2) Plowed or cultivated fields.
    (3) Producing vineyards that are plowed or cultivated.
    (4) Fields in nonflammable summer fallow.
    (5) Irrigated pasture land.
    (6) Orchards of fruit, nut or citrus trees that are plowed or cultivated.

(7) Christmas tree farms that are plowed or cultivated.
(8) Swamp, marsh or bog land.

(d) Where vegetation is maintained less than 30.48 cm (12 inches) in height, is fire resistant, and is planted and maintained for the specific purpose of preventing soil erosion and fire ignition.

1256: Minimum Clearance Provisions - PRC 4293

Minimum clearance required by PRC 4293 shall be maintained with the specified distances measured at a right angle to the conductor axis at any location outward throughout an arc of 360 degrees.

Minimum clearance shall include:

(1) Any position through which the conductor may move, considering, among other things, the size and material of the conductor and its span length;
(2) Any position through which the vegetation may sway, considering, among other things, the climatic conditions, including such things as foreseeable wind velocities and temperature, and location, height and species of the vegetation.

1257: Minimum Clearance Provisions - PRC 4293

The minimum clearance provisions of PRC 4293 are not required:

(a) Where conductors are;
  (1) Insulated tree wire, maintained with the high density, abrasion resistant outer covering intact, or,
  (2) Insulated self-supporting aerial cable, maintained with the insulation intact, or,
(b) On areas described in 14, CCR, 1255 (c);]
(c) Except;
  (1) Dead and decadent or rotten trees, trees weakened by decay or disease, leaning trees and portions thereof that are leaning toward conductor(s) and any other growth which may fall across the conductor and break it are removed or trimmed to remove such hazard.
  (2) The trunk of any tree is not required to be removed when sound and living, and is the supporting structure to which conductor(s) are attached.

1258: Tree Lines

When electric conductors and subordinate elements are fastened to living, sound trees, commonly referred to as tree lines, the requirements of PRC 4292 and 4293 shall apply the same as to a pole or tower line.

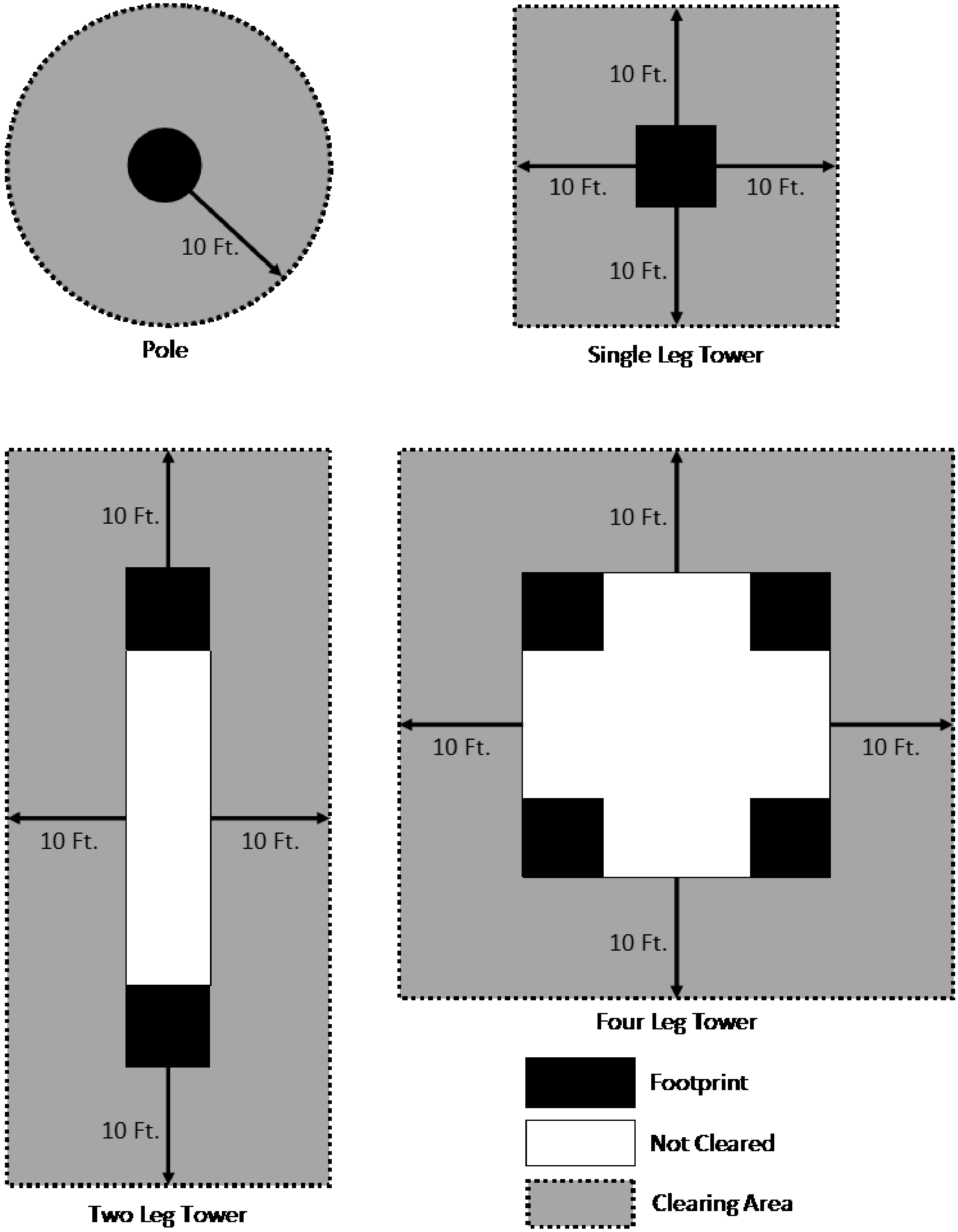


Figure 10: PRC 4292 and 14 CCR 1251 Definition of Outer Circumference Examples (Plan View at Ground Level)

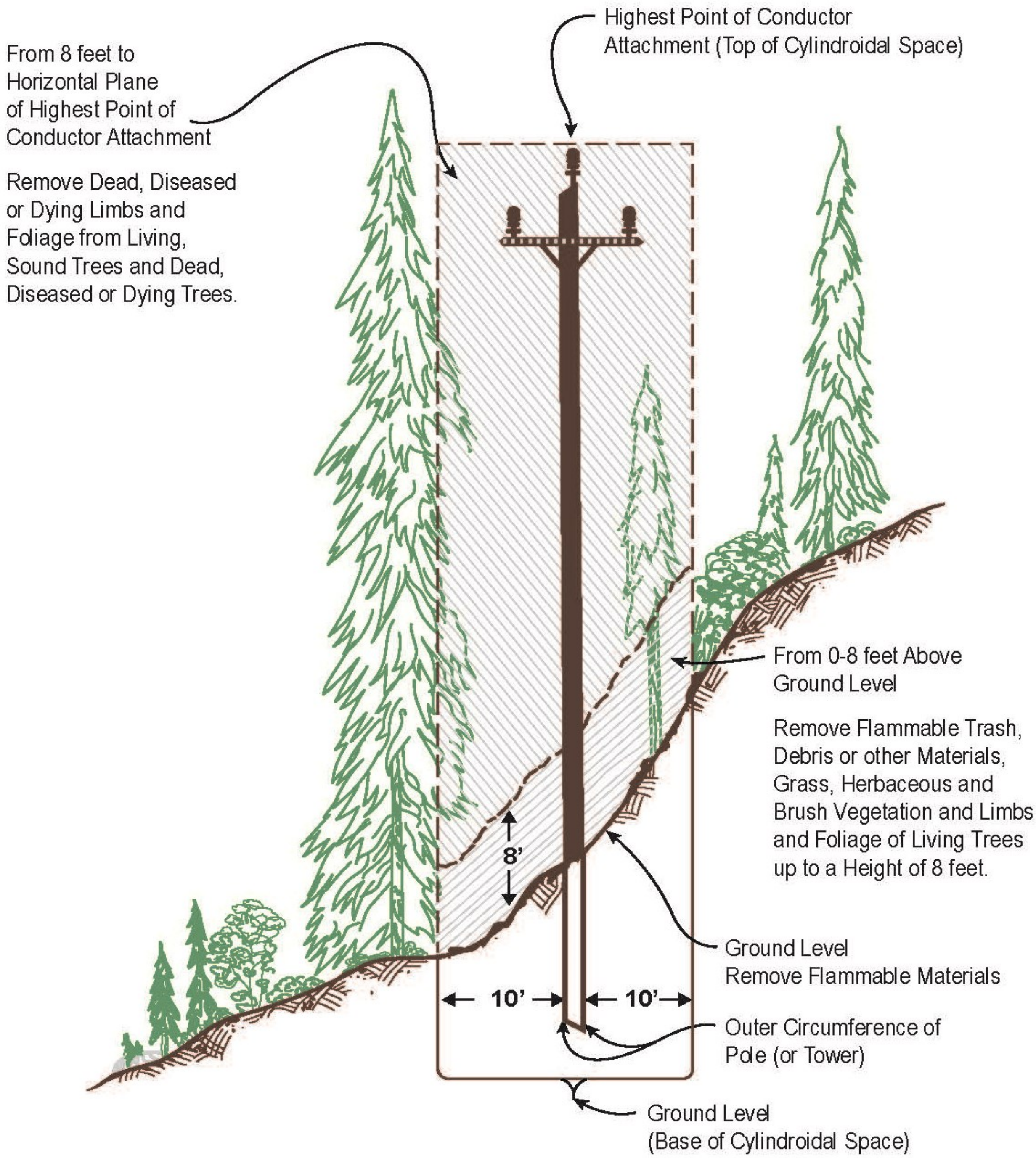


Figure 11: PRC 4292 and 14 CCR 1254 Fire Break Clearance Requirements around poles and towers

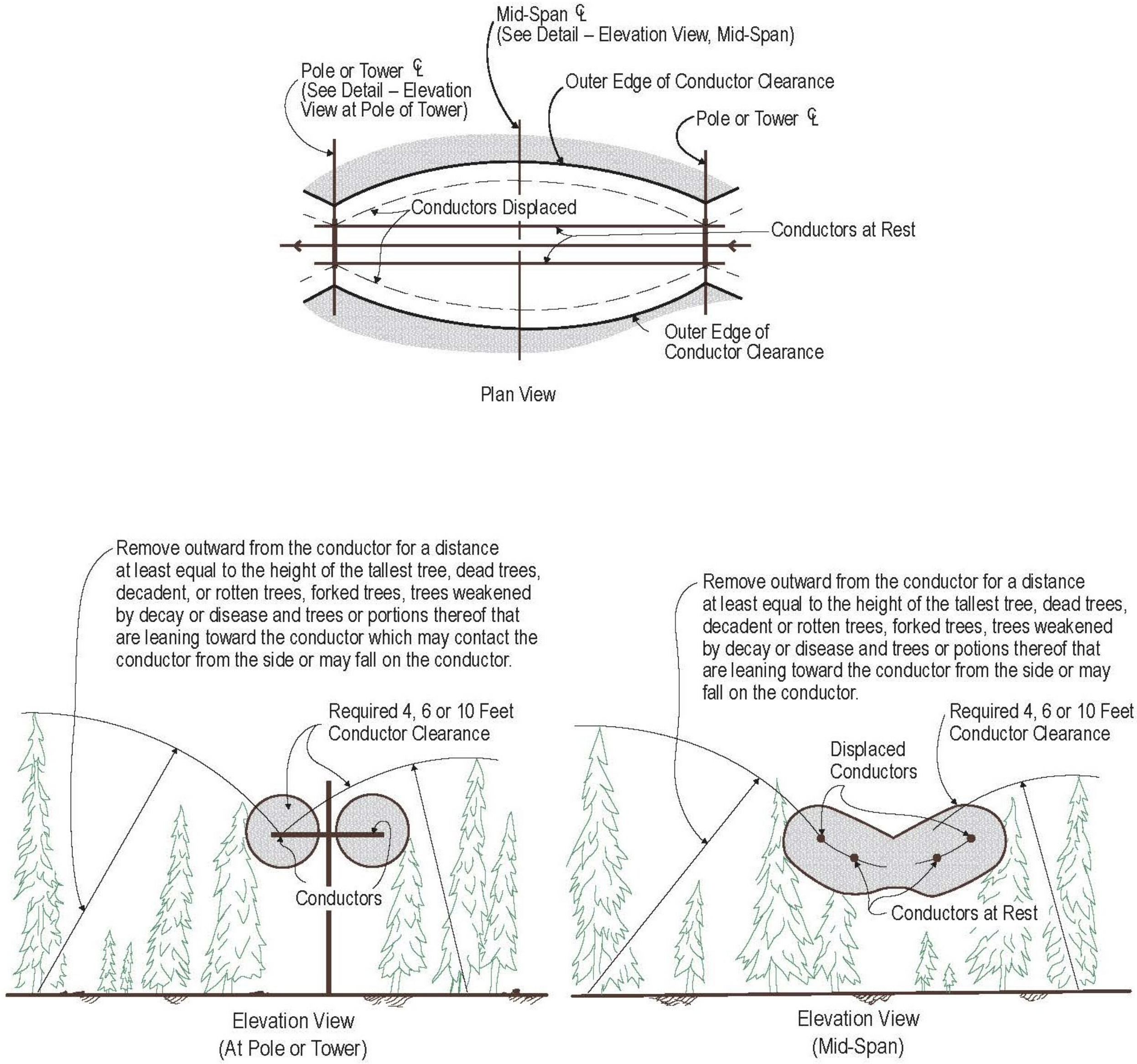


Figure 12: PRC 4293 and 14 CCR 1256 Conductor Clearance Example

CPUC General Order No. 95
This is a book containing a great many specific rules intended primarily to ensure safe construction, maintenance, operation or use of overhead electrical lines. Utility personnel must be intimately familiar with it. California Public Utilites Commission GO 95 Page

Protection agency personnel should be generally familiar with it since, although they have no responsibility for enforcing it, they can be of great help to the utilities by observing and reporting to the utility's infractions such as broken insulators or cross arms, deformed structures, sagging conductors, etc.

Code of Federal Regulation Title 36
261 – Prohibitions

261.10: Occupancy and Use

The following are prohibited:

(a) Constructing, placing or maintaining any kind of road, trail, structure, fence, enclosure, communication equipment, or other improvement without a permit.

261.50: Orders

(a) The Chief, each Regional Forester, each Experiment Station Director, the Administrator of the Lake Tahoe Basin Management Unit and each Forest Supervisor may issue orders which close or restrict the use of described areas within the area over which he has jurisdiction. An order may close an area to entry or may restrict the use of an area by applying any or all of the prohibitions authorized in this subpart or any portion thereof.
(b) The Chief, each Regional Forester, each Experiment Station Director, the Administrator of the Tahoe Basin Management Unit and each Forest Supervisor may issue orders which close or restrict the use of any forest development road or trail.
(c) Each order shall:
    (1) For orders issued under paragraph (a) describe the area to which the order applies;
    (2) For orders issued under paragraph (b), describe the road or trail to which order applies;
    (3) Specify the times during which the prohibitions apply if applied only during limited times;
    (4) State each prohibition which is applied;
    (5) Be posted in accordance with Section 261.51.
(d) The prohibitions which are applied by an order are supplemental to the general prohibitions in Subpart A.
(e) An order may exempt any of the following persons from any of the prohibitions contained in the order:
    (1) Persons with a permit authorizing the otherwise prohibited act or omission. The issuing officer may include in any permit such conditions as he considers necessary for the protection or administration of the road, trail, or National Forest System or for the promotion of the health, safety, or welfare of its users.
    (2) Owners or lessees of land in the area.
    (3) Residents in the area.
    (4) Any Federal, State, or local officer, or member of an organized rescue or fire fighting

force in the performance of an official duty.
(5) Persons engaged in a business, trade or occupation in the area.
(6) It is prohibited to violate the terms or conditions of a permit issued under (e) (1).

(f) Any person wishing to use a Forest development road or trail or a portion of the National Forest System, should contact the Forest Supervisor, Director, Administrator or District Ranger to ascertain the special restrictions which may be applicable thereto.

261.52: Fire

When provided by an order, the following are prohibited:

(a) Building, maintaining, attending or using a fire, campfire or stove fire.
(b) Using an explosive.
(c) Smoking.
(d) Smoking, except inside a building or vehicle, or while seated in an area at least three feet in diameter that is barren or cleared of all flammable materials.
(e) Going into or being upon an area.
(f) Possessing, discharging or using any kind of fireworks or Pyrotechnic device.
(g) Entering an area without any firefighting tool prescribed by the order.
(h) Operating an internal combustion engine except on a road.
(i) Welding or operating acetylene or other torch with open flame.
(j) Operating or using any internal or external combustion engine on any timber-, brush- or grass- covered land, including trails traversing such land, without a spark arrester, maintained in effective working order, meeting either (i) Department of Agriculture, Forest Service Standard 5100-la; or (ii) the 80 percent efficiency level determined according to the appropriate Society of Automotive Engineers (SAE) recommended Practices J335 and J350.
(k) Violating any state law specified in the order concerning burning, fires or which is for the purpose of preventing, or restricting the spread of fires.

Note: Under this subsection (261.52(k)) any or all of the state statutes and regulations quoted in Parts I and II of Appendix B, as well as other state laws, may be adopted as federal regulations.

Local Ordinances

Local agencies may have more restrictive regulations. Check with your local fire department.

Terms and Conditions of Permits and Easements

These vary so widely depending on date of issuance, location, issuing authority and type of use that no general statements regarding them are relevant. Some are quite restrictive while others are so loose as to be almost meaningless. Most lie somewhere between the two extremes but two are seldom alike. Employees of both utilities and fire agencies should obtain copies of the specific permits and easements pertaining to the power lines for which they are responsible and become thoroughly familiar with them. Copies or resumes of them should be inserted in this Guide.

HAZARD TREES/VEGETATION CLEARANCE

The table of contents entries below are hyperlinked to their correlating sections in the document. Clicking on an entry will take you to its section.

Introduction

Types of Risk Associated with Trees in Proximity to Overhead Electric Utilities
Trees may pose a variety of risks to energized electrical utility lines, which are categorized into two basic groups: conflicts that occur (1) when trees grow into contact with conductors, or (2) where trees fail and contact conductors. This section focuses on tree failure.

Scope of this Section: Reasonably Foreseeable Field Conditions
For the purposes of this section of the Guide, the scope is limited to reasonably foreseeable and observable field conditions that are not extreme. The reason for this limitation on scope is practical. As explained below, trees fail when force(s) exerted upon them are stronger than the trees. If the scope of this Guide were all-encompassing, intended to apply to all possible field conditions, then it becomes clear that *every* tree can be hazardous once the forces become strong enough (i.e. during extreme conditions) to cause it to fail.

Persons Conducting Tree Failure Inspections
Persons conducting tree failure inspections should be properly equipped, trained and possess the knowledge and experience necessary to draw conclusions and make decisions about whether a tree requires abatement at the time of the review. Training should be documented. Judgment about the significance of defects, conditions, and response growth can be guided by applying knowledge and experience, examining local species failure profiles, literature and site conditions. The person's knowledge and experience should include review of recent publications about factors affecting tree health and sustainability, like climate change.

Inspection Cycles
A tree failure inspection is time-dependent; the inspection and conclusions are drawn at the time of the inspection, and conditions may change before the next inspection is made. Usually, in the utility context, inspections happen at regular intervals. Making the determination that a tree does not require abatement work means that at the time of the inspection, the inspector determined that the tree was not hazardous.

A time frame until the next inspection (inspection frequency) should be specified; this is usually the inspection interval determined by the utility and agencies accordingly.

Overhead Electric and Communication Utility Assets, Footprint and Power Line Movement: "The Target"
For the purposes of this discussion, the "target" associated with the consequences of tree failure are the overhead electrical facilities (power lines and electrical equipment) and communications infrastructure that frequently occur on the same poles[1]. In this Guide, these are jointly referred to as "utility infrastructure."

Overhead electric infrastructure generally occurs in fixed locations and so is considered a static target. Within the fixed "footprint" of the utility infrastructure, conductors may move within a limited range. This occurs when forces such as wind, ice, or thermal heating (causing sag) move

[1] While contact with vegetation may not create fire hazards directly, communication infrastructure does pose a risk of pulling on or snapping communication lines, which could pull down or contact power lines.

the conductors; the forces may warrant consideration when evaluating whether a tree can strike the infrastructure when it fails.

Frequently, communications facilities occur on dedicated, single use poles, without overhead electric facilities. For the purposes of fire prevention, single use overhead communications pole lines are generally not an ignition source because the energy within communications infrastructure is usually insufficient to ignite a fire.

Defining Structural Tree Failure
Tree failure is the structural failure of the root system, stem (trunk), or branches. Structural failures may occur when the forces acting on a tree exceed the strength of the tree structure or the soil supporting the tree. Even a structurally strong tree may fail when a load or force is applied that exceeds the strength of one or more of its parts.

Steps to Inspection

Likelihood of Impact: Can the Tree(s) Strike the Utility Infrastructure?
When determining the likelihood of impact to utility infrastructure, the inspector should consider factors including tree height, lean, weight distribution, and whether the tree has a path to the conductors.

If a tree cannot strike the utility infrastructure during reasonably foreseeable conditions, it is not hazardous to it.

The target zone (where tree failures may have impacts) for utility infrastructure is typically defined in terms of distance from conductors, distance from the edge of a maintained corridor, or distance from the centerline of a right-of-way (ROW). In cases involving critical utility infrastructure such as substations and high voltage transmission lines, the target zone may include any tree tall enough to strike the target.

For a branch failure, the target zone is the area in which the branch could strike and is evaluated using the same general principles.

Trees and branches may sometimes fall in unusual ways, striking outside of what would normally be considered the target zone. The direction of a tree failure is often closely related to wind direction, canopy distribution and terrain. The following factors can all influence the direction and consequences of tree failure:

Height
To pose a threat of impact, a tree must be tall enough so that if it fails, it may strike utility infrastructure. Included in tree height is slope and topography.

When the tree is shorter than the utility facilities, or the distance to the conductor is more than the height of the tree or the part most likely to fail, the tree is very unlikely to strike. The inspector should consider slope during this portion of the evaluation and should evaluate the tree from the point it will “hinge,” which may not be ground level.

Path

Often, obstructions occur between the subject tree and utility infrastructure that reduce the likelihood that the tree will strike the electric facilities in the event of failure. Trees or branches, buildings or other objects that stand between the tree being assessed and utility infrastructure may shield the infrastructure from contact. If strong and numerous enough, the trees or objects may intercept the subject tree or branch and prevent it or direct it away from striking facilities.

Lean

Trees with more than a slight lean away from utility infrastructure are unlikely to strike the infrastructure, regardless of their weight distribution. Within reasonably foreseeable field conditions, such trees are generally not hazardous to infrastructure. Otherwise, the direction and amount of lean should be carefully evaluated.

Trees exhibit either corrected or uncorrected lean. Corrected lean is usually exhibited in hardwood trees that naturally grow in a non-linear fashion (decurrent) or in conifers that grow upright (excurrent) after a force has moved the bole off vertical (like snow-loading). Corrected lean may not constitute a structural weakness in a tree.

Uncorrected lean is usually caused by outside factors (wind, soil conditions, etc.) that loosen or break roots. Construction activities that sever roots or strike tree butts and boles also cause trees to lean, as does the impact of falling trees, either natural or human caused. Humps and soil mounding on the opposite side of the lean direction are often indicators of broken or loosened tree roots. Cracks in the bole and roots are often signs of a failure in progress, and abatement may be required right away.

A leaning tree can be more hazardous because of the presence of open fire wounds or cankers, especially if accompanied by rot.

Weight

The inspector should evaluate weight distribution within the tree, particularly while assessing limb failure.

Likelihood of Failure

Introduction
Although failure likelihood guidelines are available for individual defects and conditions, it is essential to consider all the compounding factors (as well as any response growth in a tree) that may have compensated for failure conditions.

Overview of Tree Defects and Site Conditions
Tree defects and conditions are typically considered individually when assessing single trees, but they can be considered in aggregate. For example, the likelihood of failure of a specific dead branch might be rated as *possible,* while the likelihood of failure of any one of several dead branches in a tree might be rated as *likely*. Similarly, two or more modes of failure (codominant stems, dead branch, etc.) might be rated in aggregate, although this is more complex to consider.

Below is a non-exhaustive list that provides an overview of tree defects and site conditions that increase the likelihood for tree failure:

- Standing dead trees and dead parts of trees
- Broken and/or hanging branches
- Cracks
- Weakly attached branches or codominant stems
- Decayed or missing wood (damage or cankers)
- Unusual tree architecture (lean, balance, branch distribution, or lack of taper)
- Loss of root support
- Shallow soils
- Insect infestation
- Diseases
- Suppressed or intermediate stems within a forest stand
- Fire damage

Combination of Defects
When more than one defect or condition influencing the degree of hazard is present in a tree, it is said to have a combination or multiple defects. Although single defects can be severe enough to require abatement, a combination of lesser factors can also require abatement.

Site Conditions
Site conditions that can affect the likelihood of tree failure impacting electric facilities include soil type, vegetative cover, land use, topography, slope and aspect, vegetation history, past pruning history and practices, and wind exposure. Presence or history of failed trees in an area can indicate that site conditions and/or genetic characteristics of native trees may be influencing an elevated level of failure.

It is important to consider the impact of site changes (e.g., stand alterations) that open remaining trees up to environmental influences, such as forest clearing, grading activities, trenching, filling, a change in groundwater, infrastructure repair or other construction.

Root Defects

Root defects are often difficult to find and assess since tree roots are underground and not visible. However, above-ground symptoms and signs in individual trees along with patterns of decline in adjacent trees can help to identify specific below-ground defects. Defective roots are particularly dangerous because of the risk they pose. When roots are defective, all or part of an entire tree may fail. The two major kinds of root problems are physical and biological.

Physical problems include undermined soil as well as, severed, loosened, cracked, broken, exposed, and stem-girdling roots. A variety of activities can cause these root problems, including soil compaction, erosion, flooding or saturation, construction activities, prolonged heavy equipment or foot traffic, etc. Examples of root defects include but are not limited to:

- Undermined or severed roots caused by erosion or construction activity
- Root exposure and/or burial caused by grading

Biological problems are generally caused by root disease and decay fungi. Examples of indicators of biological root defects include but are not limited to:

- Open butt rot wounds at the ground line
- Excessive casting of exterior needles, yellowing, abnormally short needles and internodes, rounding off the upper crown, and fungus fruiting structures in the cambium layer at the root crown (ground level or on the trunk of the tree) or in nearby decayed stumps. These indicators often occur in conifers.

Heart Rot

Heart rot/butt rot can be a problem in trees of all sizes but are typically more common and severe in mature and over-mature trees. In hardwoods, failures occur often in branches or in forks rather than in the bole, but potential bole failures should not be overlooked.

Basal fire scars and mechanical injury to the bole can be an entry point for organisms that cause butt and heart rot. Species especially susceptible to this kind of defect are non-resinous conifers such as white and red fir. When examining these species, it is very important that fire scars are checked for the presence and amount of decay.

When assessing for heart/butt rot, an inspector’s assessment should include but not be limited to the following items:

- Open wounds showing visible rot
- Old wounds that have partially or fully healed over
- Conks anywhere on the bole of the tree
- Hollow trunks detected by rapping on the tree trunk or by use of an increment borer
- Decreasing crown vigor
- Cracks or splits not caused by lightning
- Swelling or cankers on the bole
- Wildlife cavities
- Presence of carpenter ants or termites
- Number, size and distribution of fungal fruiting bodies
- Broken or dead tops
- The amount of solid radial wood remaining where visible

- Poor live crown ratio (% live crown)
- Poor diameter-to-height ratio

An inspector may need to conduct an invasive inspection to determine the extent of decay where detected. They may also need to sound supporting wood in the decayed area. If an inspector elects to abate a tree, further invasive inspection techniques may not be required.

Trunk Deformities
Deformities can weaken the bole and increase the chance of breakage at the point of deformity. Deformations are caused by but not limited to the following factors:

Dwarf Mistletoe and Rust Cankers
Swellings of the bole resulting from infection by dwarf-mistletoe can be prevalent on conifer species. When these swellings first begin, there is minimal weakening of the trunk. As the cambium in the oldest part of the swelling dies, structural weakening becomes more prevalent.

If the tree is a resinous species, the wood around cankers may remain sound for years; if non-resinous, the tree may develop structural weaknesses, particularly when the affected area is significant in relation to the size of the bole.

Human Interference with Growth
Flattening of the tree trunk may be caused when pieces of wood or steel are attached to trees as building supports. Fastening wires and cables around the trunk for various purposes also can deform and weaken a tree.

Forked Trees and Codominant Tops
The inspector should scrutinize forked trees carefully for cracks, included bark, pitching or bleeding or for callus ridges outlining and closing older cracks. The inspector should also look closely for signs of rot that may affect a fork enough to render the tree hazardous.

In general, forked trees with tight v-shaped (not u-shaped) forks are susceptible to splitting and breaking off at the fork. This problem is more prevalent in mature trees in which the members of the fork have grown long and heavy.

Hardwoods may be more susceptible to failures associated with codominant tops than conifers because of their wide, spreading crown that can result in greater leverage at the fork or other limb attachments.

Limbs and Limb Deformities

Introduction
Limb failure can occur when the combined forces exerted on the limb exceed the strength of the limb at its weakest point. These forces include the weight of the limb itself as well as the forces imposed by wind, snow, ice and rain.

Limb failures also occur because of the presence of defects such as: decay, cracks, splits and breaks, holes from animals, birds (mostly woodpeckers) or insect activities and compression defects.

In general, hardwoods may be more susceptible to limb failures than conifers because of basic differences in crown form, which in the hardwoods give rise to narrow, structurally weak crotches and to long branches which become heavily weighted at the extremities. In addition, there is a tendency in hardwoods for trunk rot to extend into major limbs and increase the potential for limb failures.

Limb Size: Diameter, Length and Breadth
A degree of hazard control can be achieved by removing limbs that are equal to or greater than a specified diameter, length and/or breadth. This can be achieved by pruning the limbs to reduce the amount of leverage they exert on the branch from which they radiate and its connection to the main bole. Species-specific limb failure information (i.e., limb diameter, length, breadth and position in a tree) can support abatement decisions that prevent limb failure.

Dead Limbs and Wood Durability
In conifers, the durability of dead limb-wood depends on whether a species is resinous[2]. Dead limbs of resinous conifers can persist for some time. Dead limbs in non-resinous species, however, may require abatement since the limbs may fail shortly after dying.

Dead limbs of hardwoods generally decay faster than limbs in conifers. This faster rate of decay in turn means dead limbs in hardwoods may also require abatement shortly after dying.

Top Defects

Dead Tops
Dead tops on living conifers, sometimes called "spike tops," may be hazardous in some cases. Dead tops in non-resinous conifer species should be abated because the wood is relatively non-durable and susceptible to attack and consequent weakening by decay fungi.

Experience indicates that spike tops in giant sequoia, incense cedar, coast redwood, pines and Douglas-fir can be less common if not structurally weakened by defects such as cracks, splits or woodpecker holes. However, caution should be used when evaluating all dead tops.

Broken Tops and Volunteer Tops
Conifers with tops that have broken out are usually not considered to be hazardous, even though there may be rot present below the break, and a short length of decayed trunk may remain. In each case, however, the inspector should examine the ratio of decayed wood to sound wood.

[2] Resinous trees are those species where the sap has water-resistant properties that in addition to making the wood hard, help prevent the wood from decay. The species in California are usually conifers.

Volunteer tops that form following the loss of tops in conifers may be hazardous because as the tree regrows, it adds weight to wood that may be decaying. The inspector should evaluate the decayed wood-to-sound wood ratio to look for other associated defects like cracks.

Tree Species Failure Profiles

For certain tree species and sites, there are recurring patterns of tree failure. Tree risk inspectors should be knowledgeable about local species' failure patterns when performing tree risk inspections. Utility vegetation managers should monitor tree failure incidents and develop experience-based tree failure profiles for common species present in the population of trees in proximity to overhead lines.

Knowing the species and conditions that have a higher risk of failure and the most common ways in which a species may fail can aid in determining when and where within the tree to conduct hazardous tree abatement work.

Failure profiles can be developed locally or identified using the Western Tree Failure Database (formerly known as the California Tree Failure Reporting Program or CTFRP). Failure profiles may also be derived from other sources. The inspector must keep in mind that tree failure profiles are an aid to analysis, but they do not substitute for working through the steps of the inspection process. All portions of a tree being inspected should be considered, not just those that are associated with the most common failure patterns of the species.

Tree Health vs. Structural Stability

Inspectors should not confuse tree health and tree stability. High-risk trees can appear healthy in that they can have a dense, green canopy. This may occur when there is enough vascular transport in sapwood or adventitious rooting to maintain tree health, but there could still be inadequate strength for structural support.

On the other hand, trees in poor health may still be structurally stable. For example, tree decline due to certain types of root disease is likely to cause the tree to be structurally unstable, while decline due to drought or insect attack may not unless death is caused, in which case structural instability may follow.

One way that tree health and structure are linked is that healthy trees are more capable of compensating for structural defects. A healthy tree can develop adaptive growth that adds strength to parts weakened by decay, cracks and wounds.

Species-specific failure information can help in distinguishing tree health from stability.

Other Considerations

Structure

The overall structure of many hardwoods, as well as some conifers, frequently includes a combination of potentially weak forks, dense foliage caused by epicormic sprouting, and hormonal problems. Structure may also be influenced by past pruning techniques and heavy limbs. The heaviness of limbs can render them susceptible to failure where they connect to branches.

Sometimes, open cracks or callus ridges may be present as evidence of partial failure, but frequently, no such evidence is visible. Through observation and experience, the inspector may recognize these conditions and prescribe general pruning to reduce limb and crown weight.

Wind and Weather

Tree failures can occur during storms when strong wind, rain, snow or ice loads exceed the tree's capacity to withstand them. Wind speeds are affected by topography, urban settings and vegetative cover. Knowledge of regional and local climate, wind and precipitation patterns and observation of specific site conditions are important in assessing the likelihood of failure.

During wind events, defect-free trees can fail, and when wind strength increases, tree failure can be widespread. Wind speed is variable. Winds can be sustained, but they commonly occur in gusts that may exceed their reported speeds. Microbursts that produce strong lateral winds can also occur.

Trees generally adapt to their locations and to the wind speeds that commonly occur in an area. However, when field conditions around a tree change (e.g., when nearby trees are removed), a tree may be exposed to forces it did not adapt to while it grew. Careful consideration should be given to these trees, particularly if they are suppressed within the group/stand.

Most trees have enough strength to resist occasionally higher wind speeds. If a region is prone to strong storms or heavy snowfall and such events are likely to occur before the next inspection interval, the inspector should consider the likelihood for failure during such events. Orientation to prevailing winds and the amount of canopy a tree has should be considered.

Many weak and defective limbs are eliminated under snow and ice conditions. This natural testing and elimination of defective and weak limbs does not occur in trees below the snowline. Consequently, the limb hazard potential can be greater in such areas.

Normal and Extreme Weather

Storms can be classified into broad categories based on frequency of occurrence, wind speed, and precipitation. The broad categories of storms are normal, extreme, and abnormally extreme. "Normal weather" is a meteorological term used to describe the weather based on a location's average temperature, wind and precipitation for the previous 30 years.

Extreme and abnormally extreme storms are less clearly defined. Normal storms occur multiple times during a defined time frame. Normal storms may include thunderstorms, snow, and light accumulations of freezing rain in areas that are subject to those conditions.

Extreme storms occur less frequently within defined time frames. These events may include severe thunderstorms, accumulations of freezing rain and straight-line winds. Some tree failures may occur during this type of weather event when wind speed exceeds the seasonal norm for a site.

Abnormally extreme storms are difficult to predict and occur infrequently. These events include tornados, hurricanes, heavy wet snow, freezing rain/ice storms or other events.

Techniques and Aids

When determining their approach to tree inspections along their facilities, utilities have the option of following the American National Standards Institute (ANSI) A-300 tree risk assessment standard per their field conditions and needs.[3]

The inspector should develop a consistent approach to conducting tree inspections. This may be a habit or formal procedure the inspector follows. Few defects are located at eye-level; therefore, inspectors must scan entire trees from the soils surrounding them to their branches and tops.

An inspector should develop the habit of looking to both sides and to the rear as well as ahead. Many defective trees will be hidden from one direction but not from other directions. Similarly, some defects can only be seen from one or two sides of a tree. Particularly in dense stands, the inspector should make side trips as necessary. This is particularly true in dense conifer stands. The screening vegetation along the edges of a ROW will often hide evidence of defects in trees.

Many conifers are over 100 feet tall, making naked eye inspections of their tops and upper branches somewhat difficult. Therefore, binoculars should be part of the standard equipment inventory.

If any indication is noted of butt, heart or sapwood rot in the lower trunk, the extent of damage should be estimated, and an increment borer can help to make this determination. Inspectors should check flat areas, splits, forks and other deformities in relation to the direction of a power line from a tree and in relation to the prevailing wind direction. If the tree, or a part thereof, does not require abatement, the inspector should go on to the next tree.

When a tree needs abatement, it must be identified for those who will do the work and for follow-up inspection. The tree should be marked with flagging, timber-marking paint or other means like GPS coordinates and/or electronic record. It should also be located by map, sketch, or bearing and distance from an identifiable object. In some cases, one or more photographs would be helpful.

Categorizing the Likelihood of Failure

The likelihood of failure within a specified time frame can be categorized using the following guidelines:

- Imminent: Failure has started or is most likely to occur very soon. Immediate action may be required.
- Likely: Failure may be expected under normal conditions.
- Possible: Failure may be expected in extreme conditions, but it is unlikely during normal conditions.
- Unlikely: The tree or branch is not likely to fail during normal conditions and may not fail in extreme conditions.

[3] ANSI A300 (Part 9) 2017 Tree Risk Assessment

The decision to abate a tree should be properly documented.

Consequences of Failure

The potential consequences of tree failure and contact with electric infrastructure are many. They include damage to human life and property, regulatory compliance enforcement actions, electric service interruption, electric facility damage and repair and fire with associated losses.

Some of these consequences are direct; others are indirect. Regardless of whether direct or indirect, consequences vary in severity and should be rated according to that severity.

NON-EXEMPT (NE) EQUIPMENT PHOTOS

Clearance Required

The photo captions below have the prefix of "NE," which stands for "Non-Exempt" in this section.

The table of contents entries below are hyperlinked to their correlating sections in the document. Clicking on an entry will take you to its section.

UNIVERSAL FUSE

Figure NE-1: Universal Fuse

Round pull ring

Figure NE-2: Universal Fuse, Fuse Link, and Expulsion End of Fuse

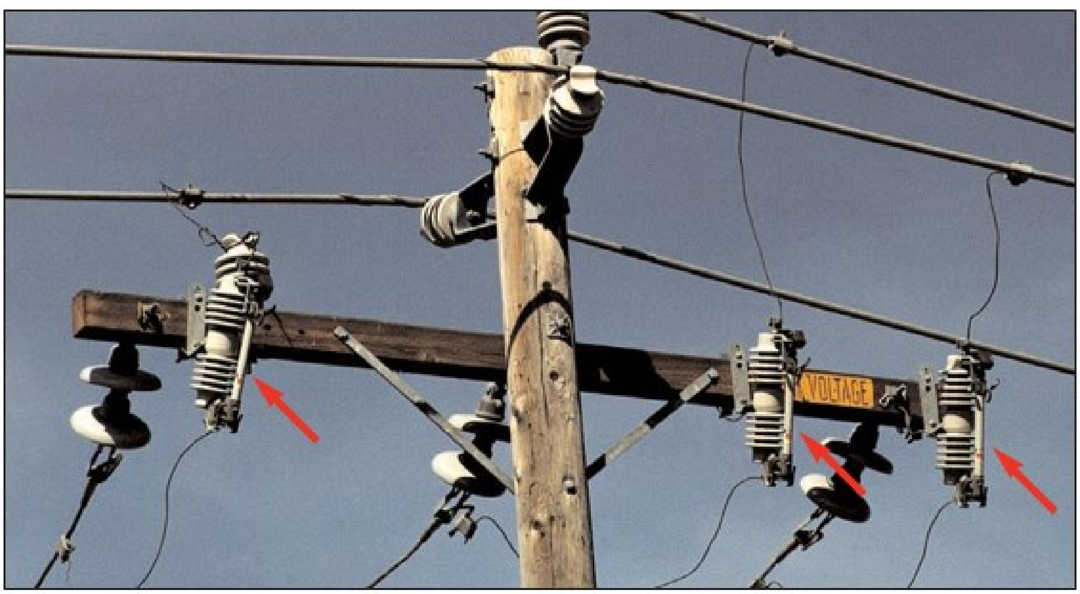


Figure NE-3: Arm Mounted Cutout with Universal Fuse

Open Link Fuse

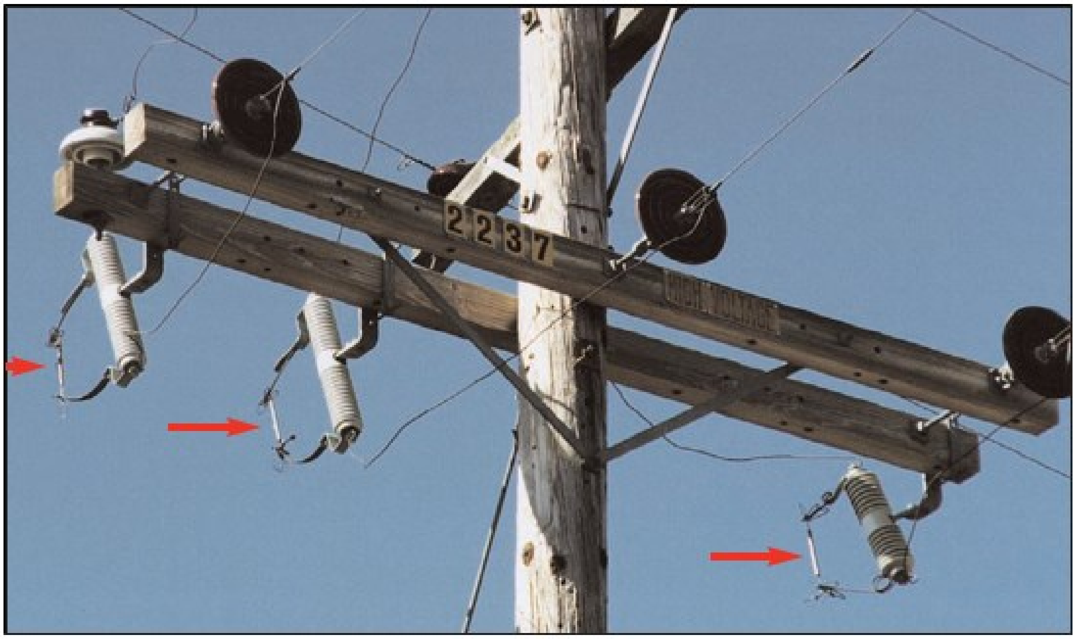


Figure NE-4: Arm Mounted Cutout with Open Link Fuse

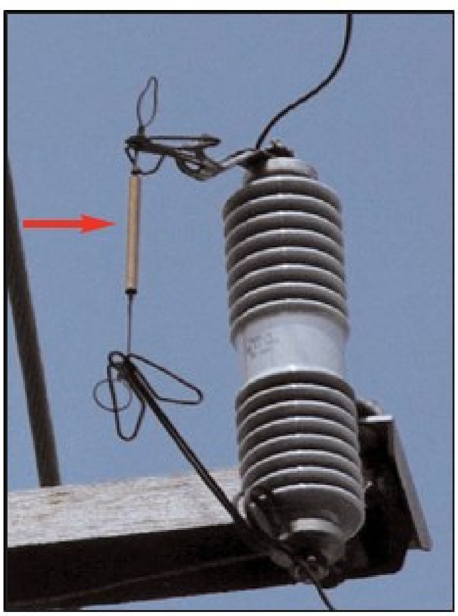


Figure NE-5: Open Link Fuse

Open Link Fuse

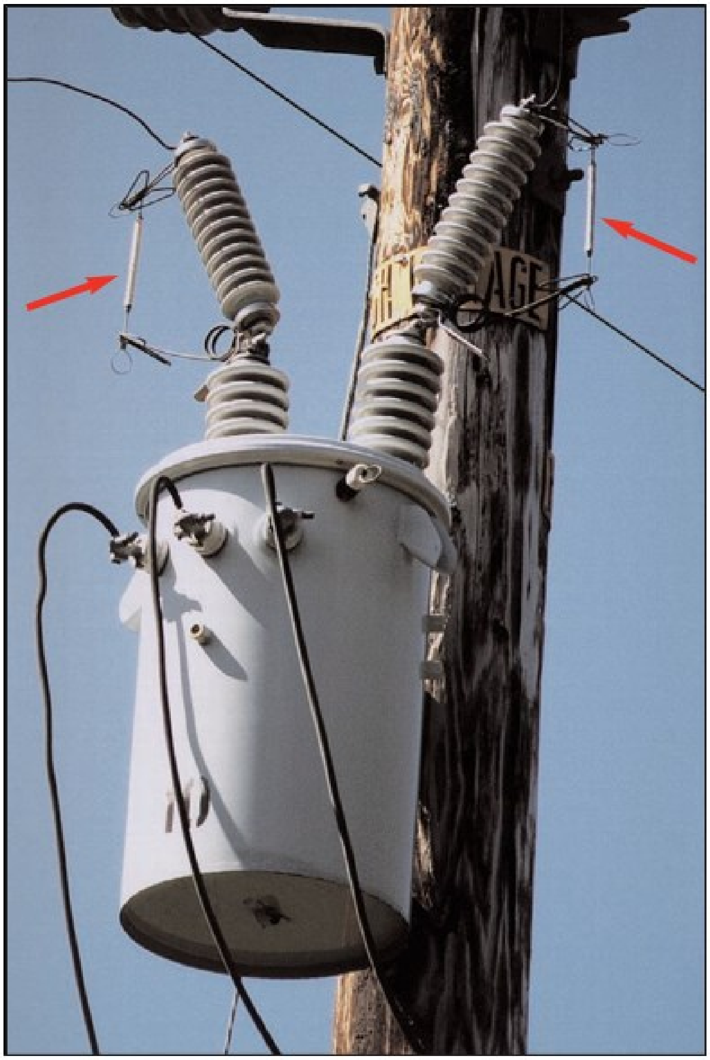


Figure NE-6: Bushing Mounted Cutout with Open Link Fuses

Figure NE-7: Close-up of Open Link Fuse

Enclosed Cutout w/ Universal Fuse

Figure NE-8: Enclosed Cutouts

Figure NE-9: Open 4kV Cutout

Figure NE-10: Arm Mounted Enclosed Cutout with Universal Fuses

Solid Blade Disconnect

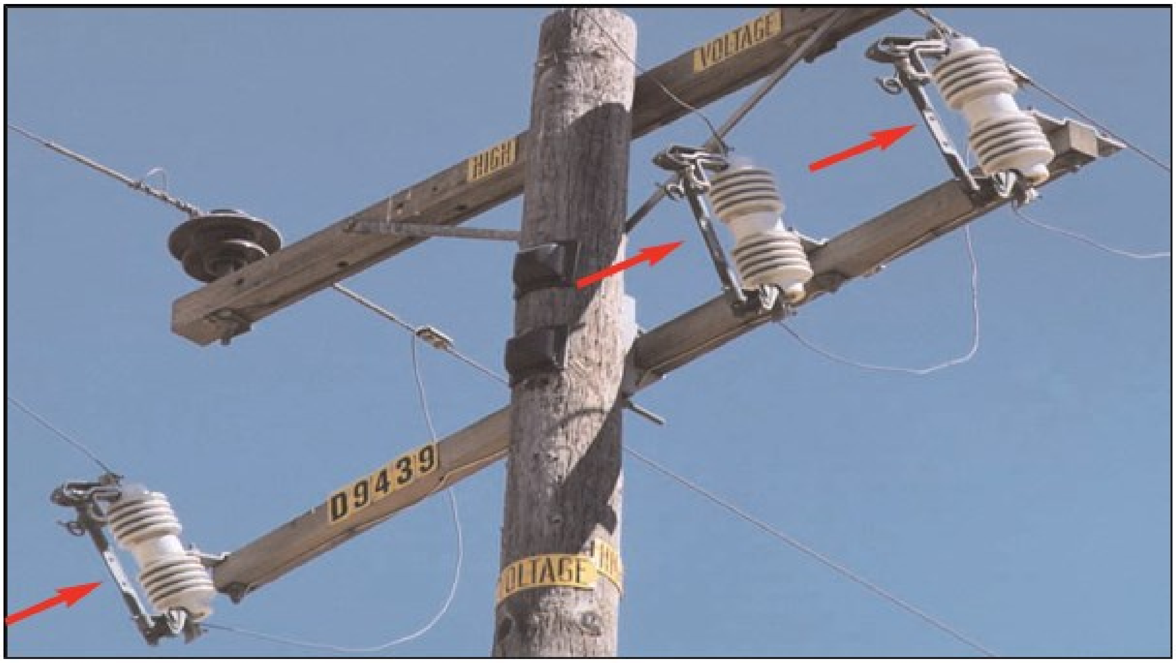


Figure NE-11: Arm Mounted Cutout with Solid Blade Disconnect (closed position)

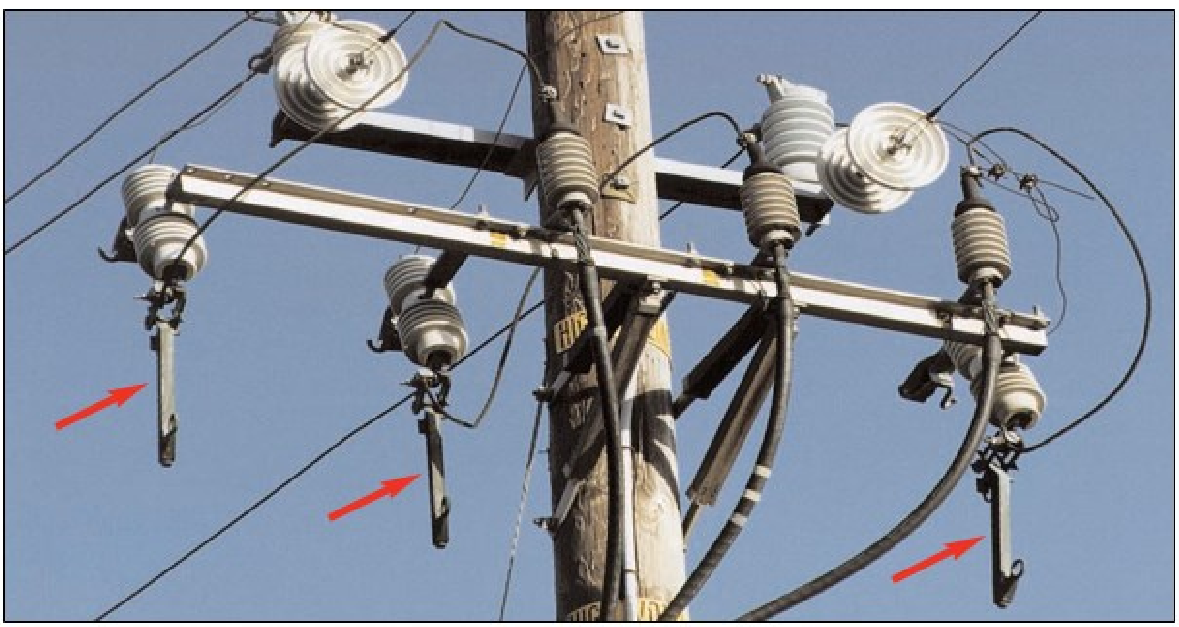


Figure NE-12: Arm Mounted Cutout with Solid Blade Disconnect (open position)

Note: Solid Blade Disconnects are exempt under certain conditions.
See Figures B-42 - B-45 on pages 96-97.

Solid Blade Disconnects

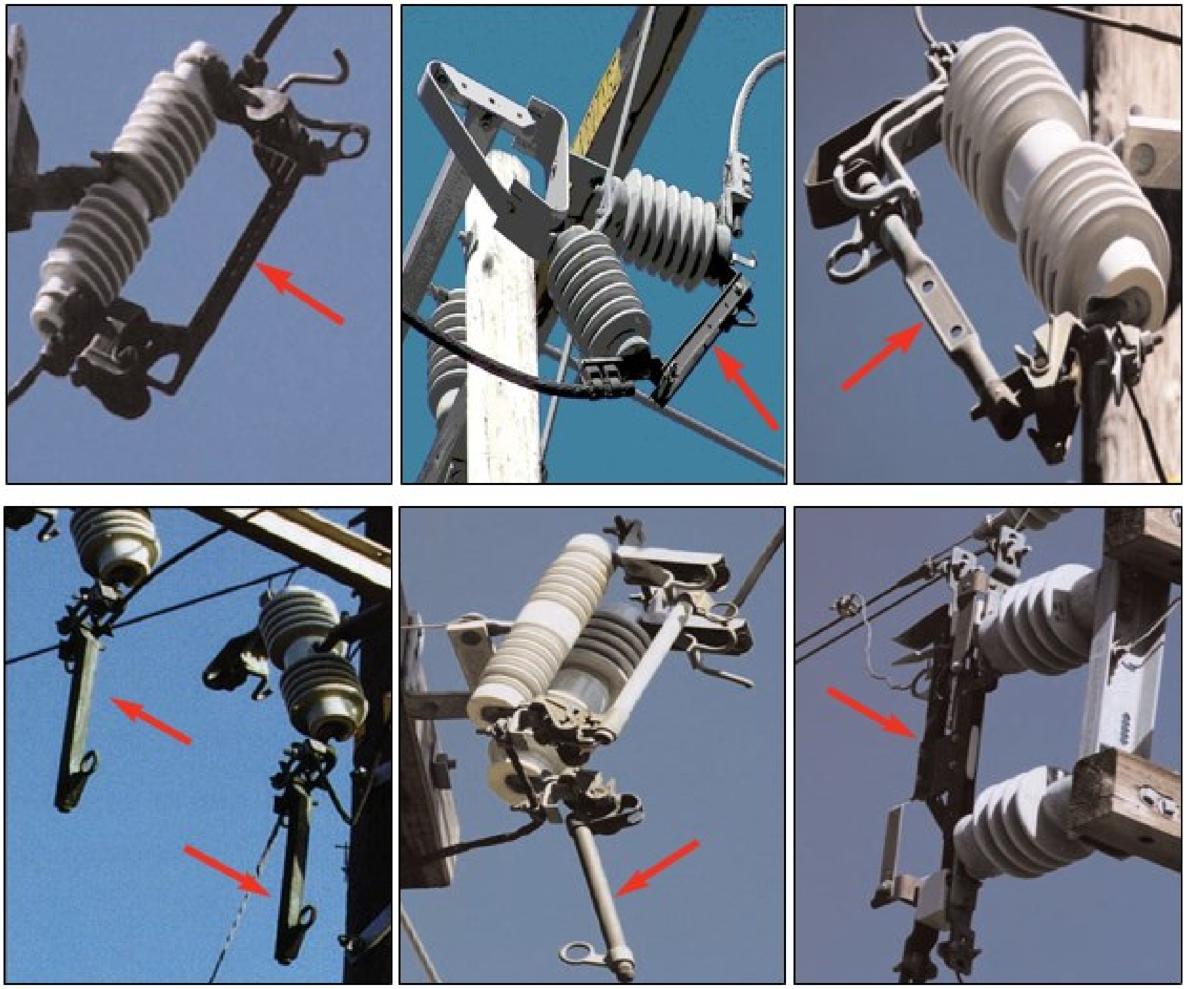
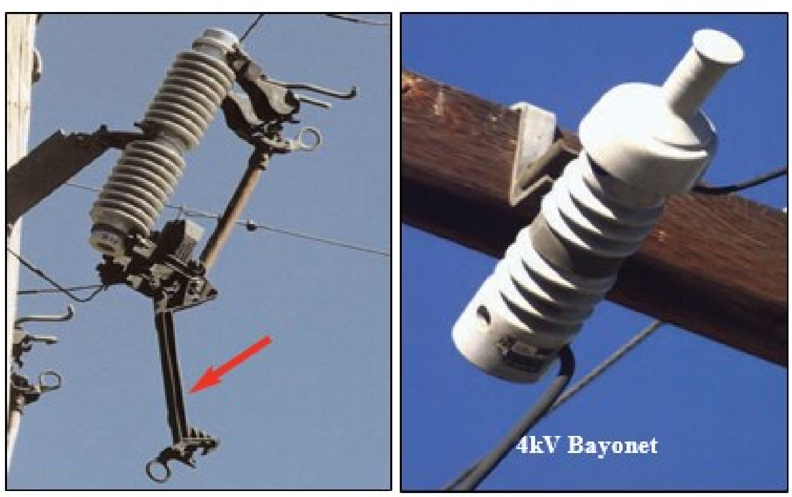
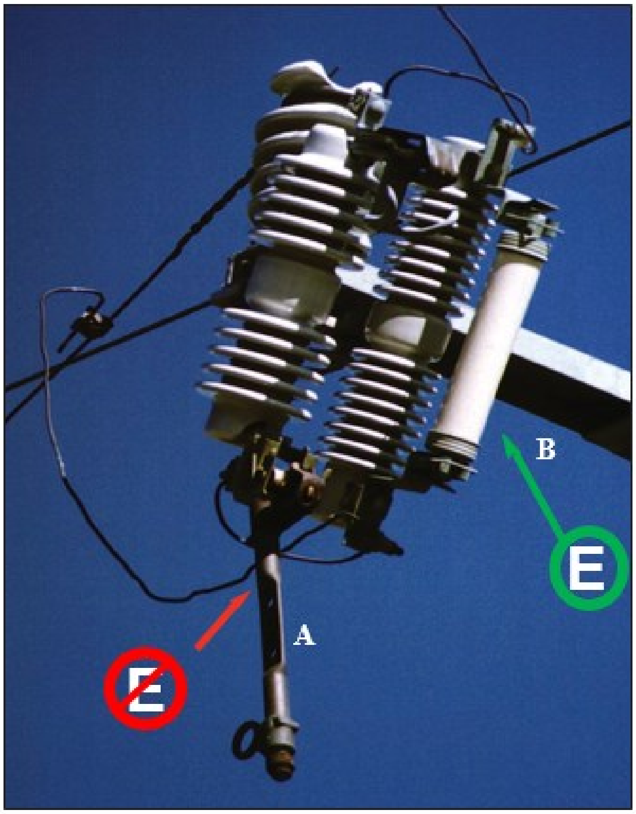


Figure NE-13: Solid Blade Disconnects



Note: Solid Blade Disconnects are exempt under certain conditions. See figures B-42 - B-45 on pages 96-97.

Solid Blade Disconnects



Note:
If a pole has a combination of exempt and non-exempt hardware it will be a subject pole and require PRC 4292 10' of clearance.

Figure NE-14:

A. Solid Blade Bypass Disconnect in Open Position

B. Arm Mounted Cutout with Non-Expulsion Fuse

In-Line Disconnect

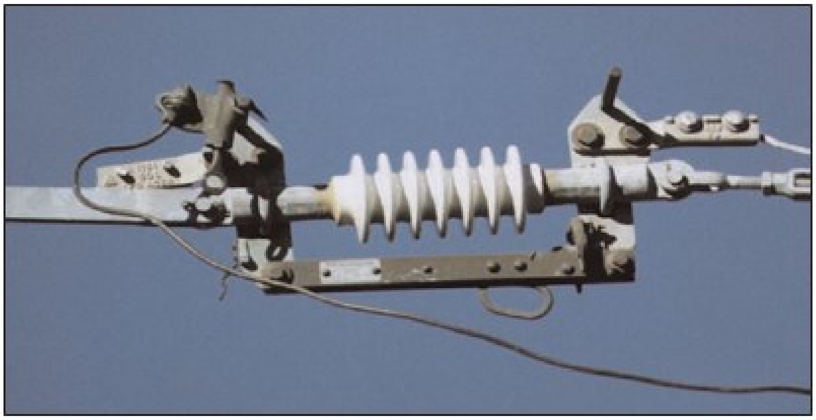


Figure NE-15: In-Line Disconnects (closed position)

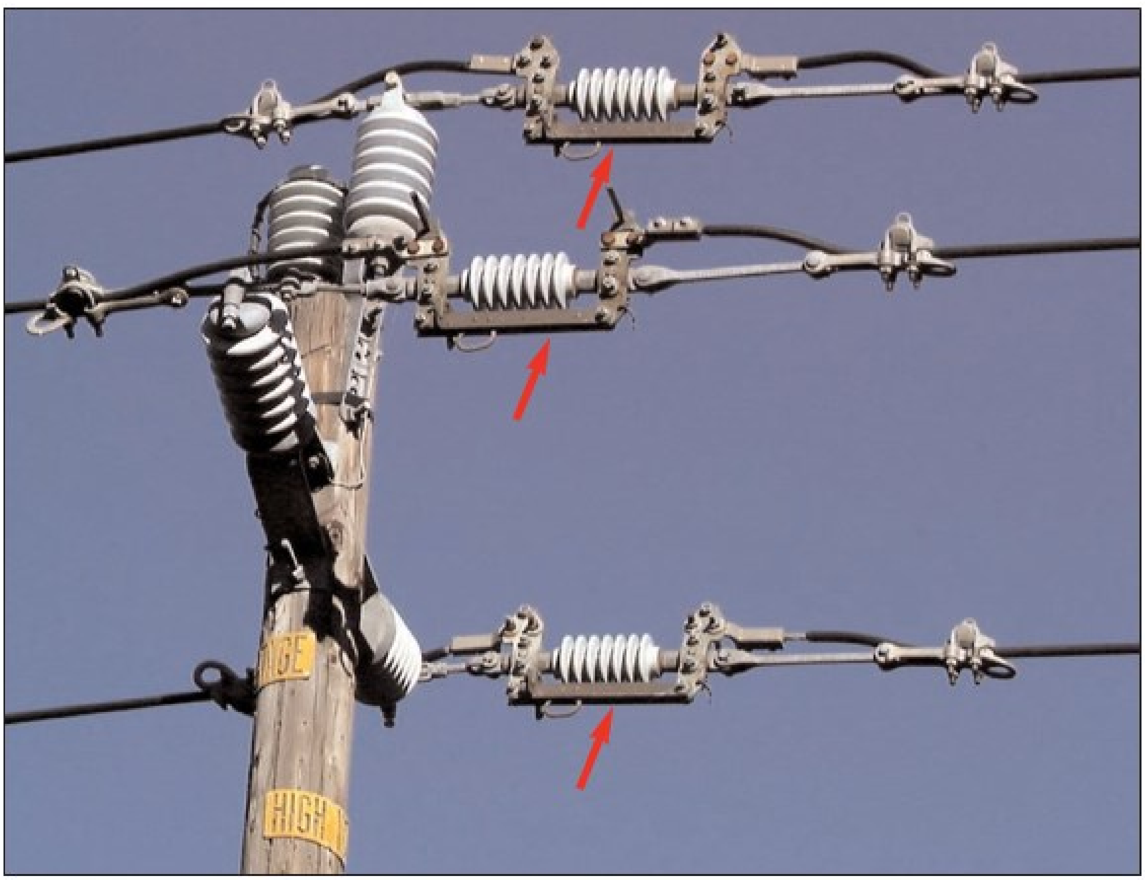


Figure NE-16: In-Line Disconnects (closed position)

Note: In-Line Disconnects are exempt under certain conditions.
See Figure B-42 on page 96.

In-Line Disconnect

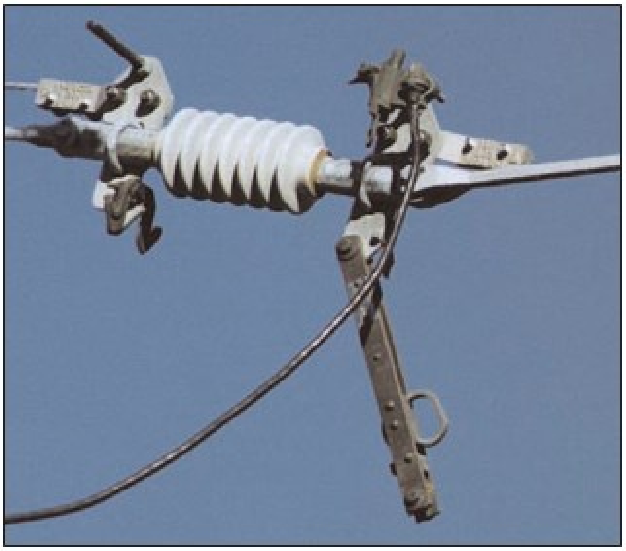


Figure NE-17: In-Line Disconnect (open position)

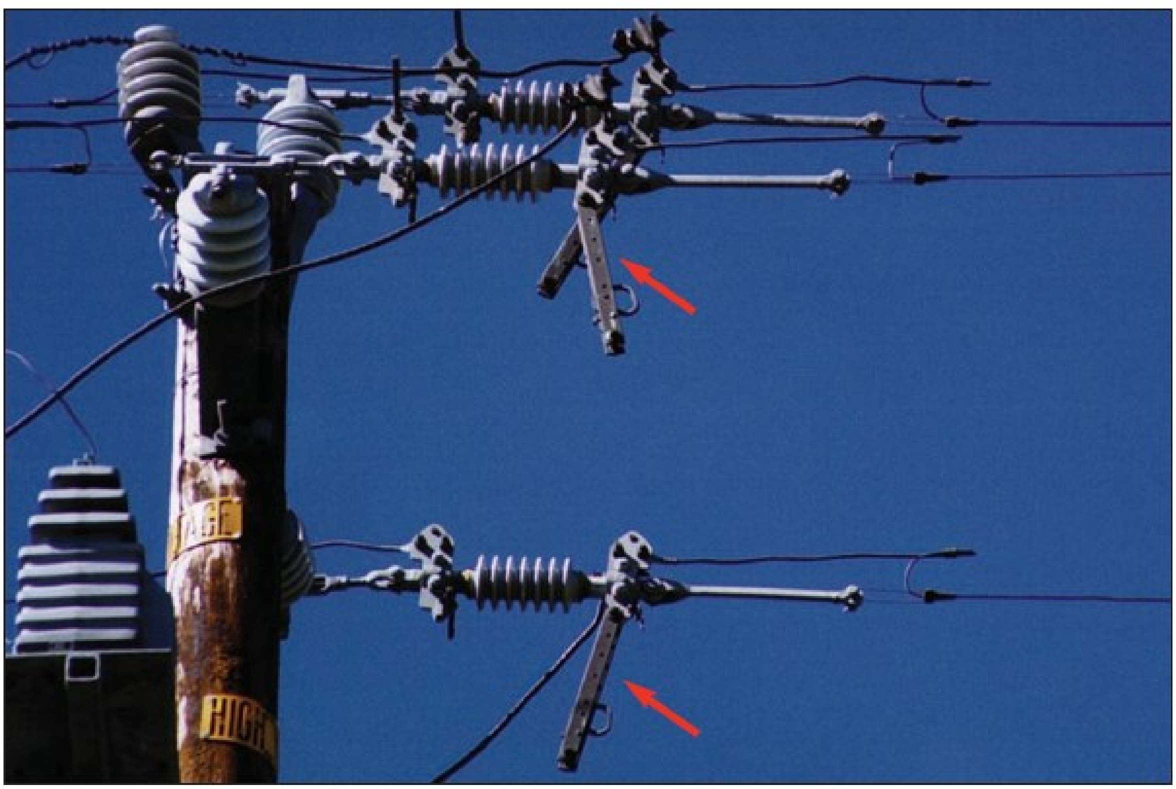


Figure NE-18: In-Line Disconnects (open position)

Note: In-Line Disconnects are exempt under certain conditions.
See Figure B-42 on page 96.

Lightning/Surge Arrester

Exempt Lightning Arresters can be found in Section B page 113 of Exempt Equipment.

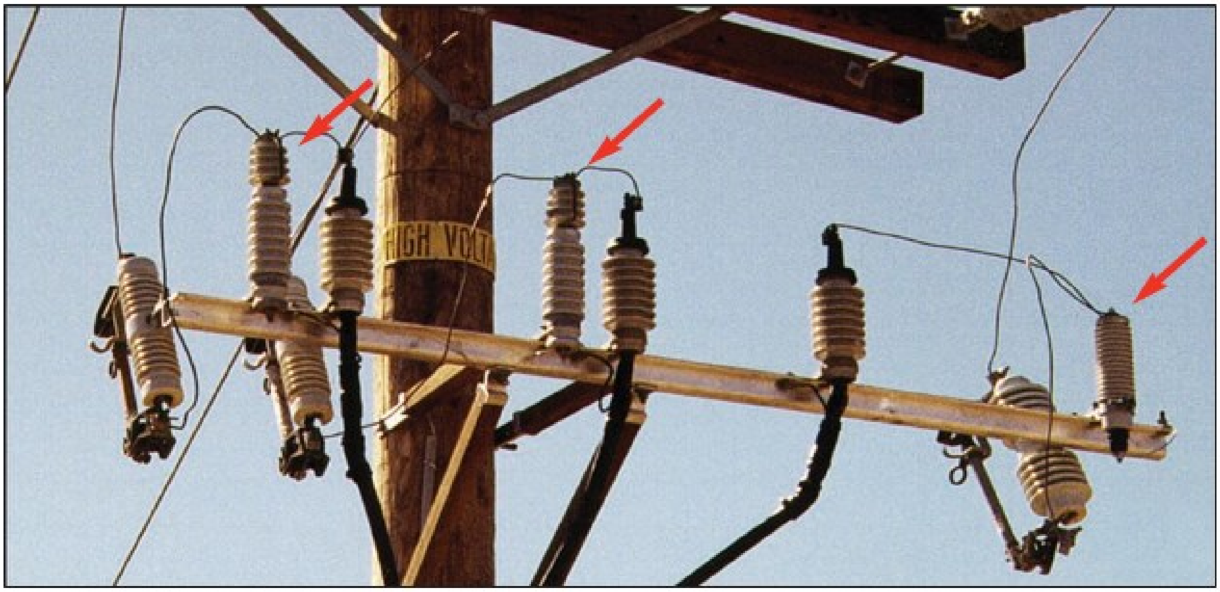


Figure NE-19: Arm Mounted Lightning Arrester (with Cable Riser and Universal Fuses)

Figure NE-20: Lightning Arrester (with Recloser)

Lightning/ Surge Arrester

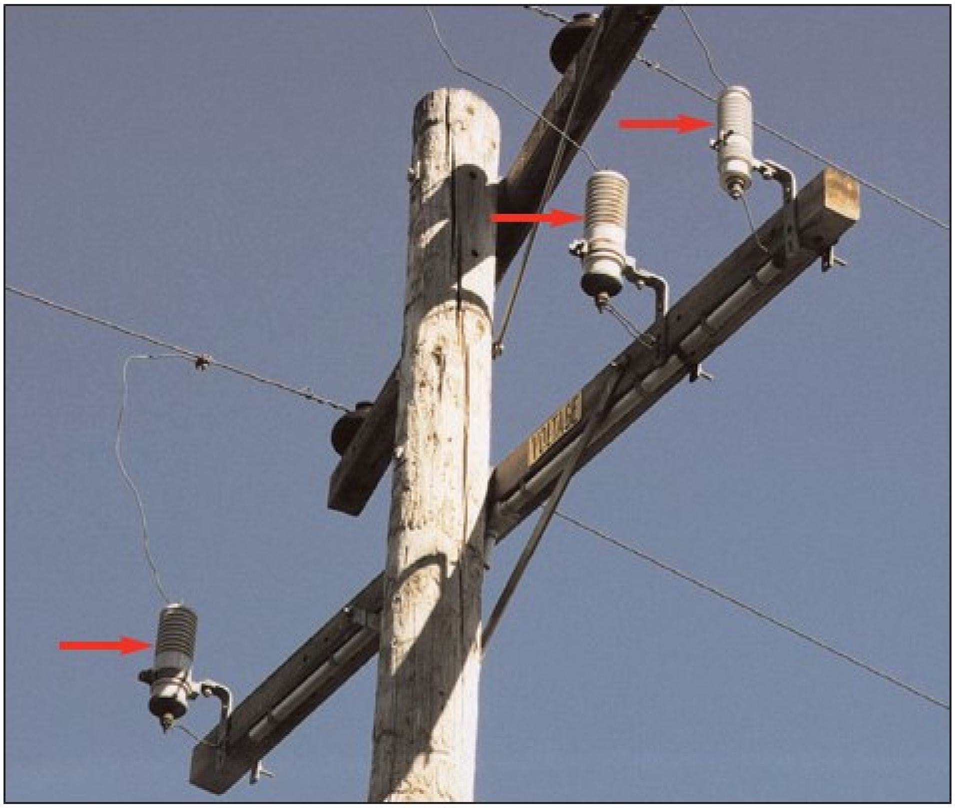


Figure NE-21: Lightning Arrester

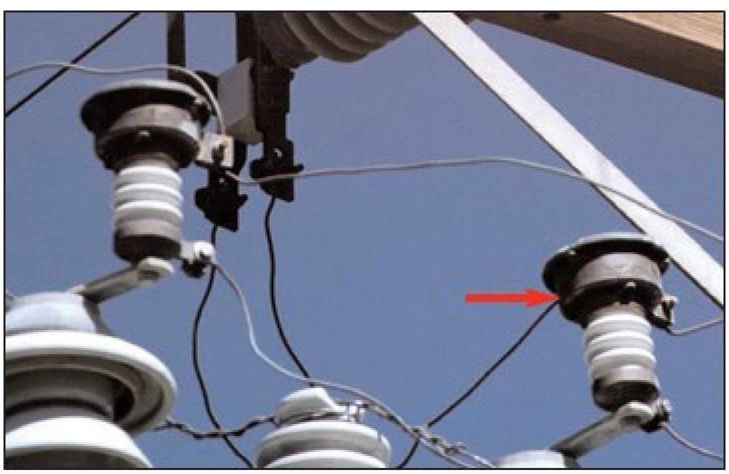


Figure NE-22: Lightning Arrester

Non-Porcelain Lightning Arrester

Figure NE-23: Non-Porcelain Lightning Arrester

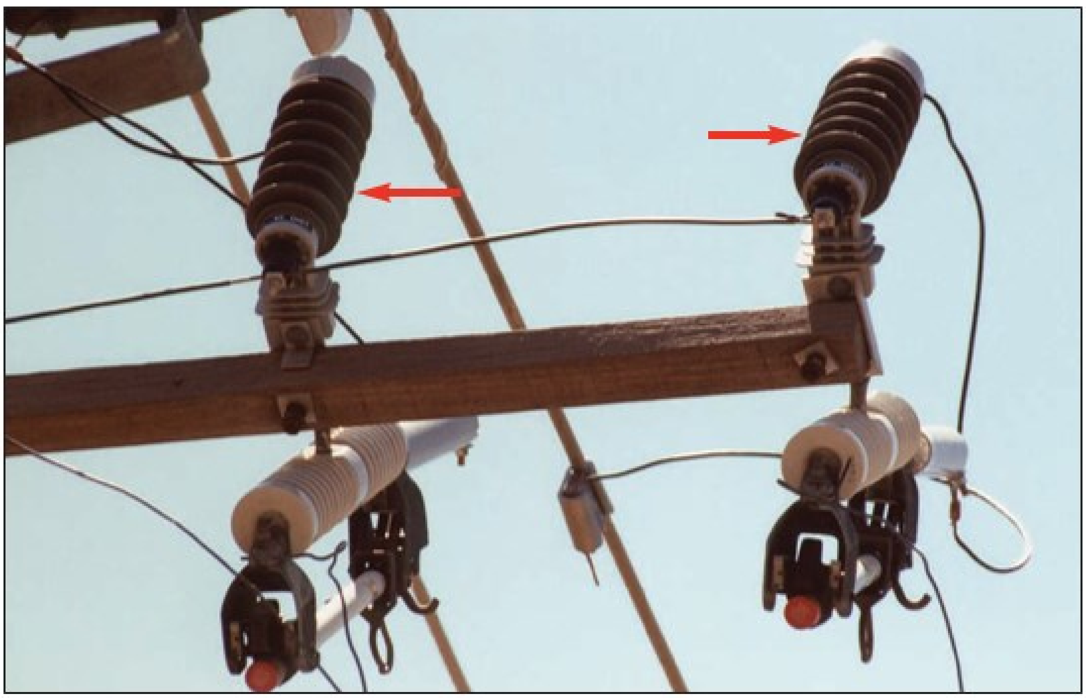


Figure NE-24: Non-Porcelain Lightning Arrester

Lightning Arrester

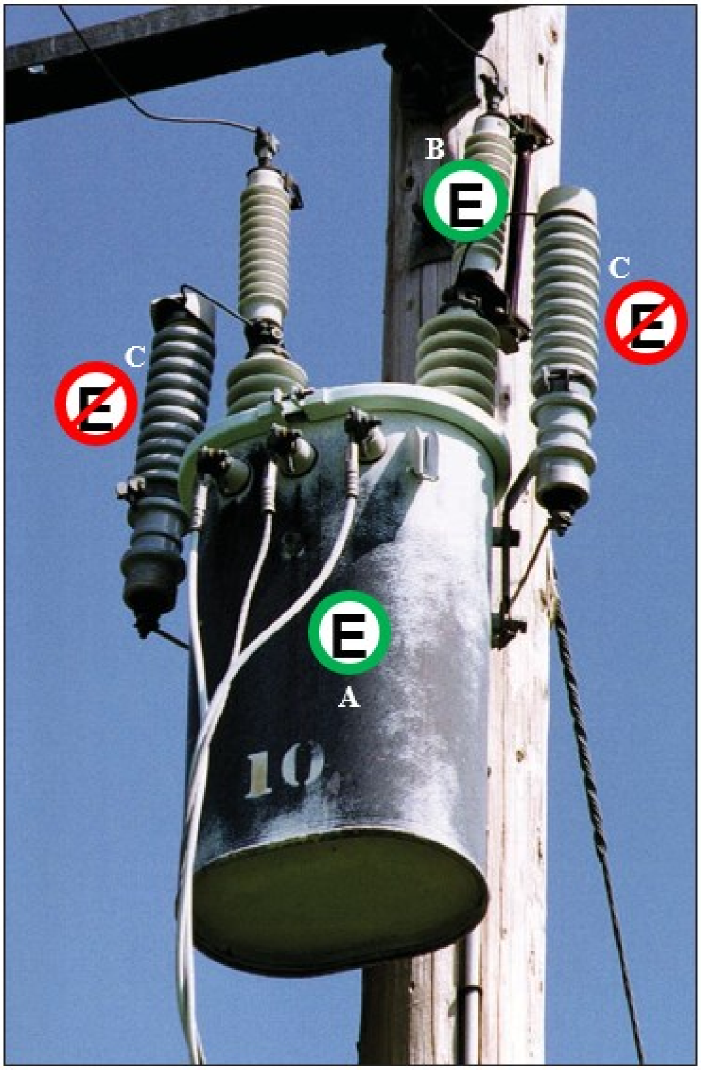


Figure NE-25: Transformer Mounted Lightning Arrester

A. Conventional Transformer E

B. Bushing Mounted Liquid Filled Fuse E

C. Lightning Arresters E

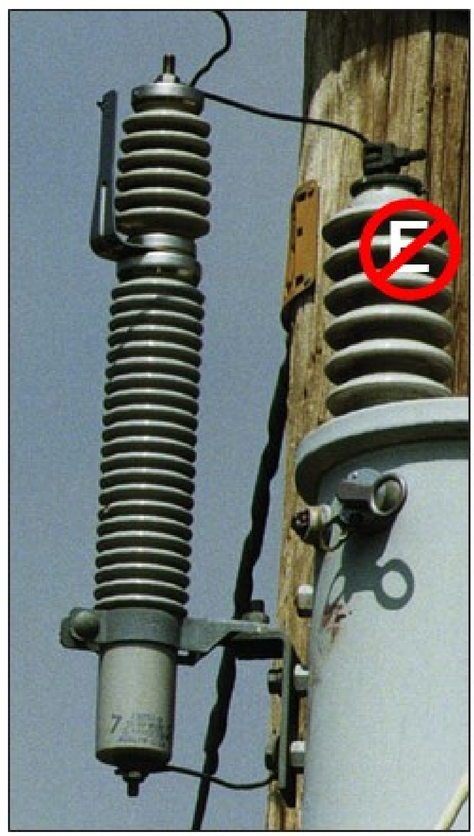


Figure NE-26: Gapped Lightning Arrester

Lightning Arrester

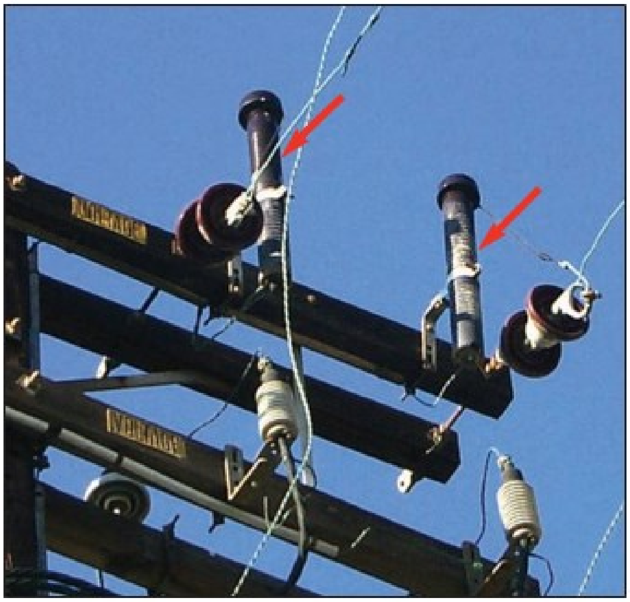


Figure NE-27: Lightning Arrester

Figure NE-28: Lightning Arrester

Hot Tap Clamp

Figure NE-29: Hot Tap Clamps

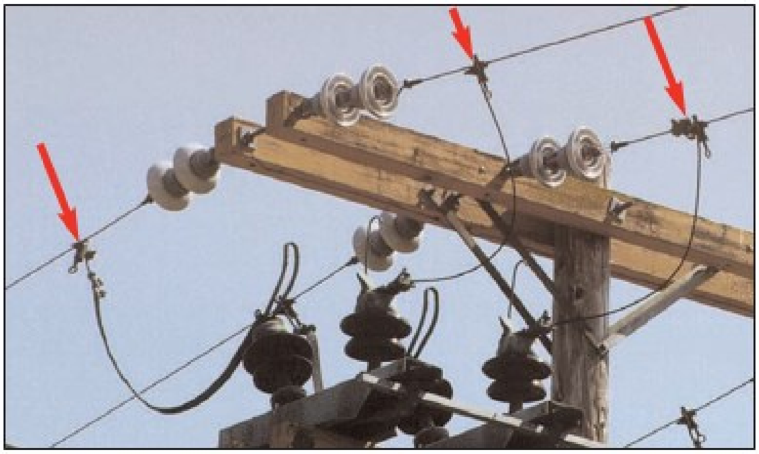


Figure NE-30: Hot Tap Clamps

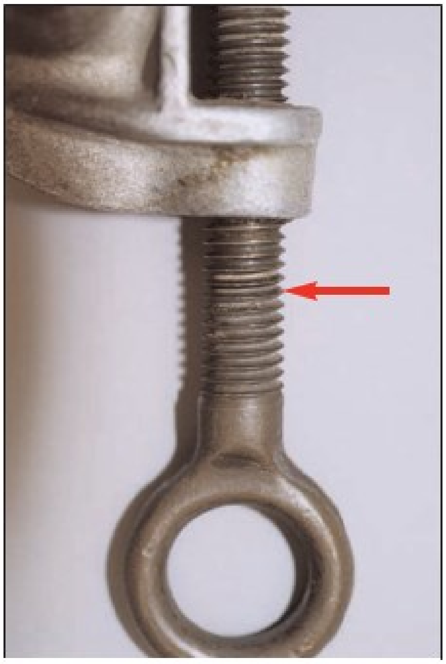


Figure NE-31: Threads

Note: Some Hot Tap Clamps are exempt. See Figure B-59 on page 103.

Split Bolt Connector

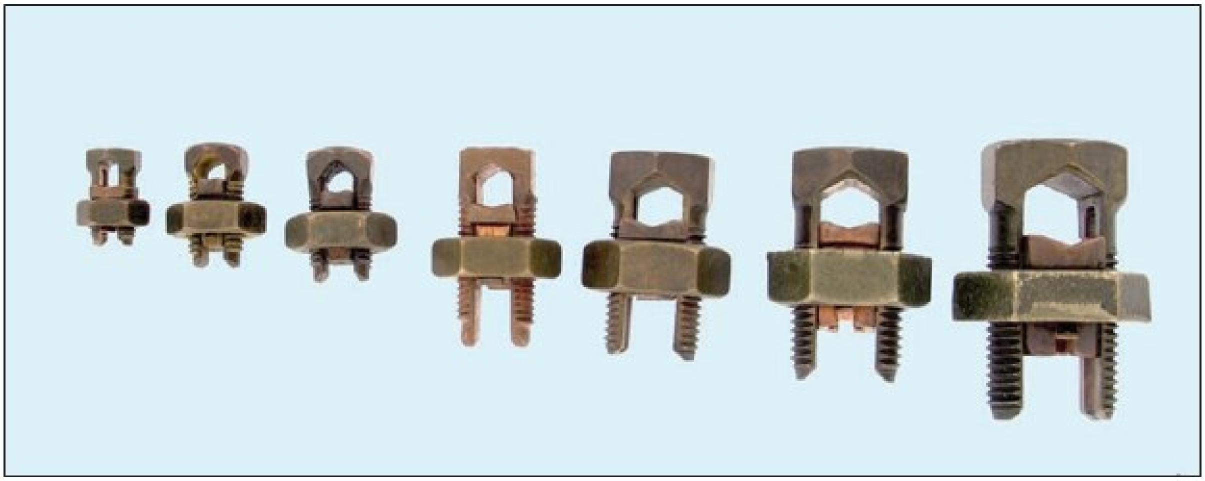


Figure NE-32 Split Bolt Connectors (various Sizes)

Note: Some Split Bolt Connectors are exempt. See Figure B-65 on page 106.

Figure NE-33: Split Bolt Connector

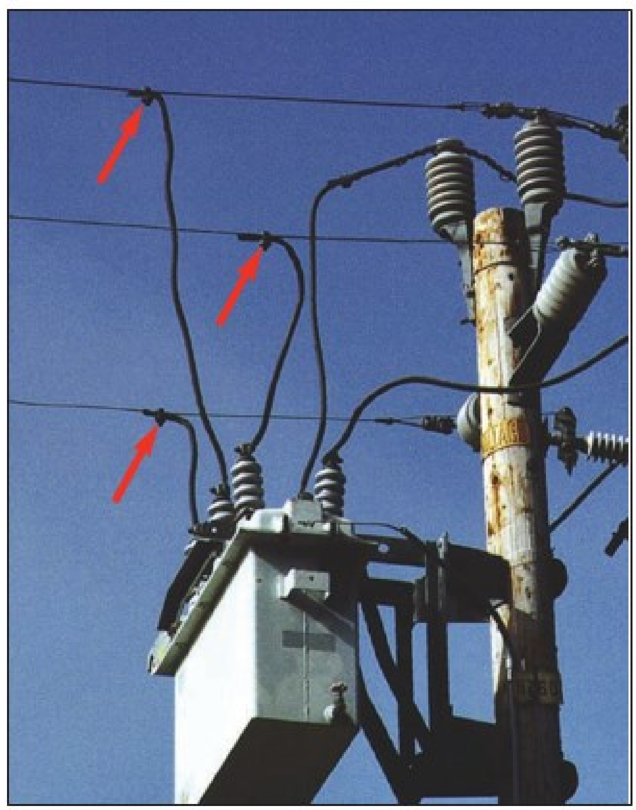


Figure NE-34: Split Bolt Connectors

Other Connectors

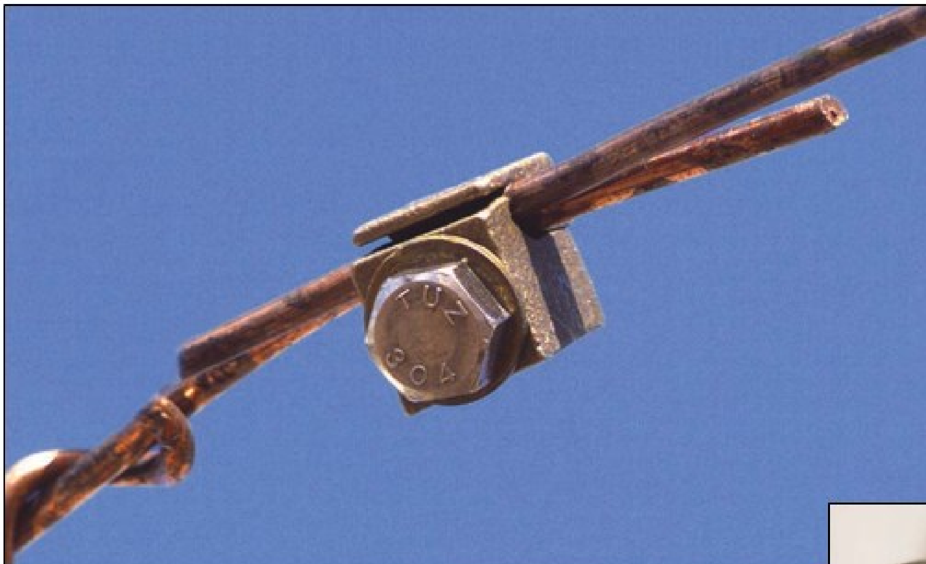


Figure NE-35: Bronze Vise Connector

Figure NE-36: Bronze Vise Connector

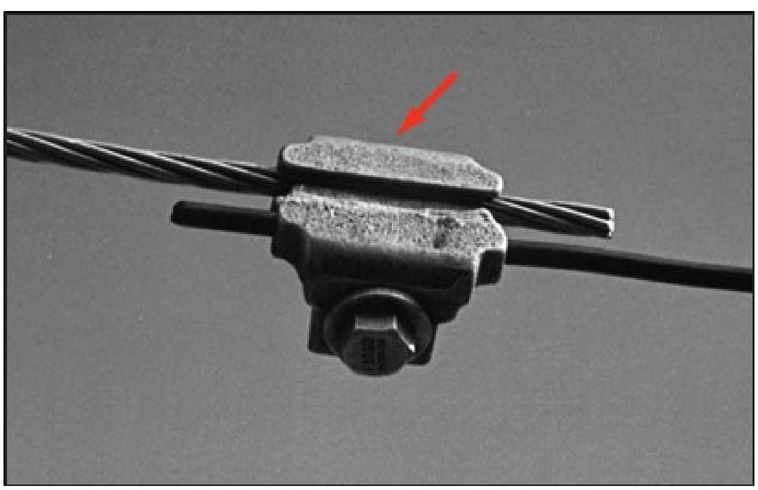


Figure NE-37: Vise Connector

Grasshopper Air Switch

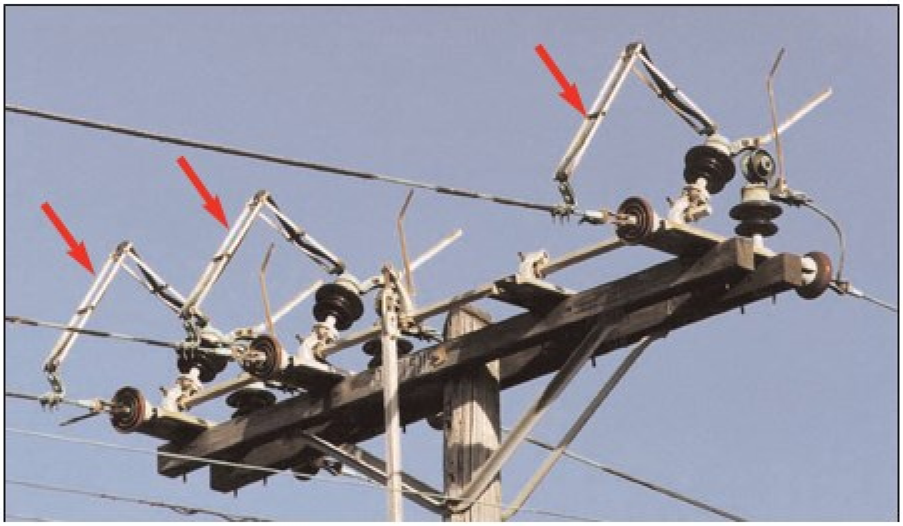


Figure NE-38: Grasshopper Air Switch (closed position)

Figure NE-39: Grasshopper Air Switch (open position)

Transmission Air Switch

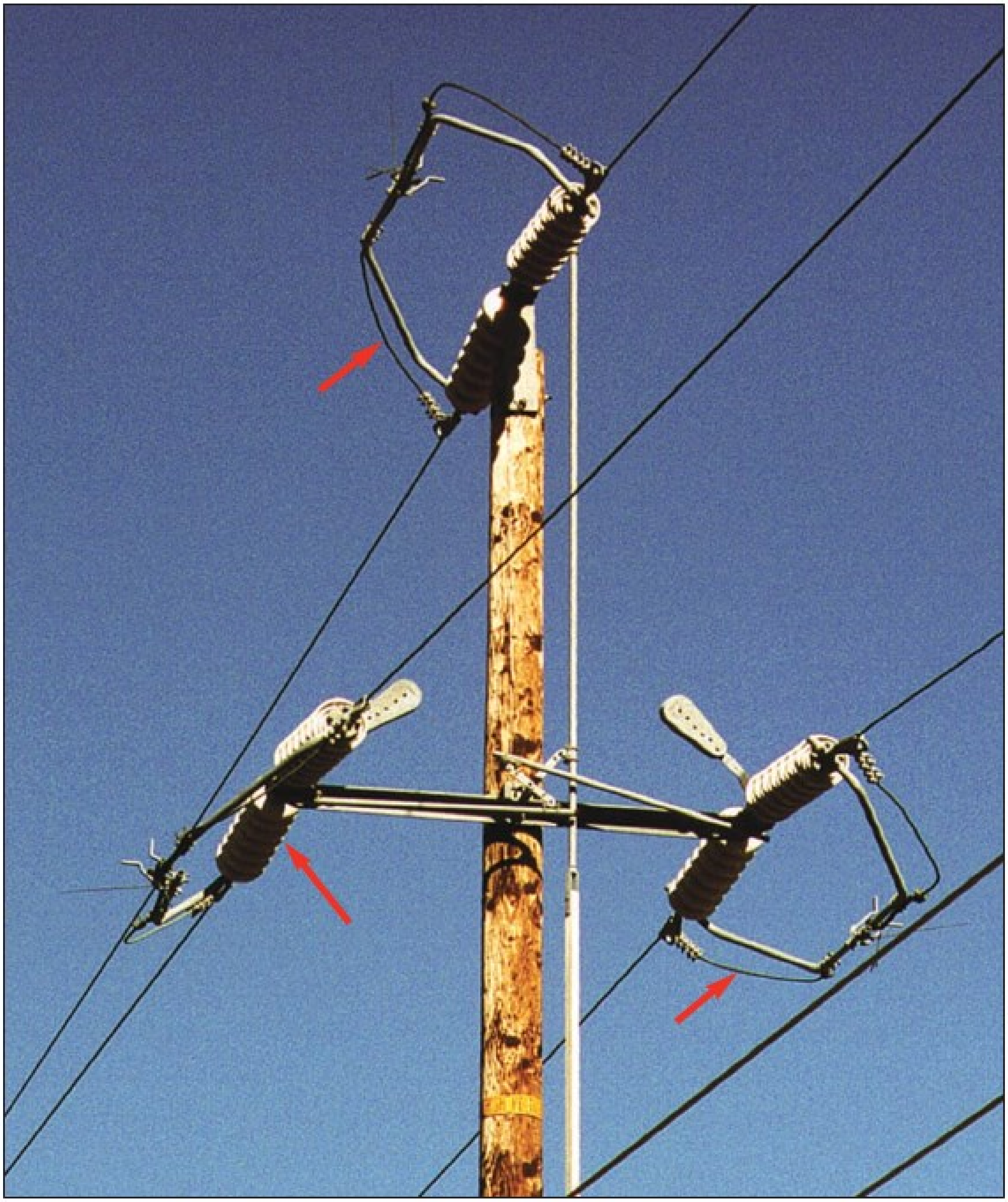


Figure NE-40: Transmission Air Switch, Pole Mounted 60kV (closed position)

Transmission Air Switch

Figure NE-41: Transmission Air Switches Tower Mounted (closed position)

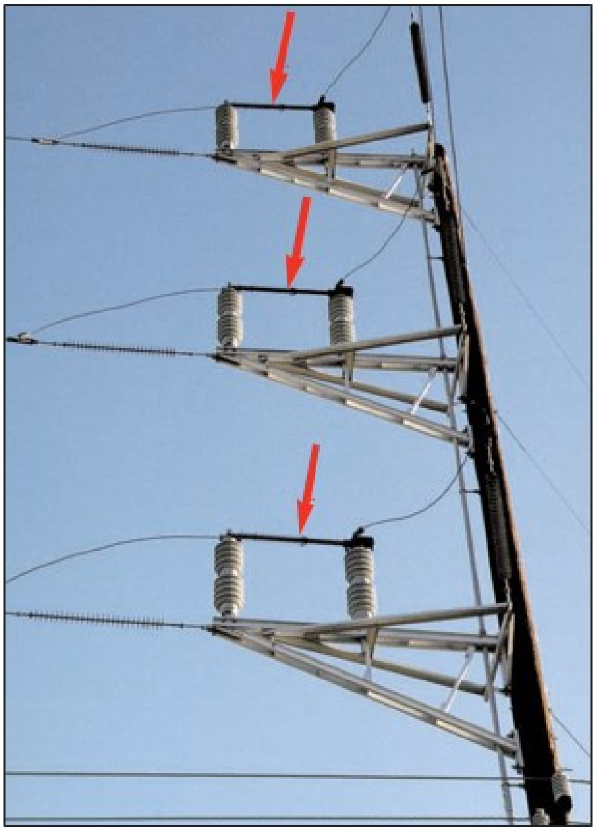


Figure NE-42: Transmission Air Switches Pole Mounted (closed position)

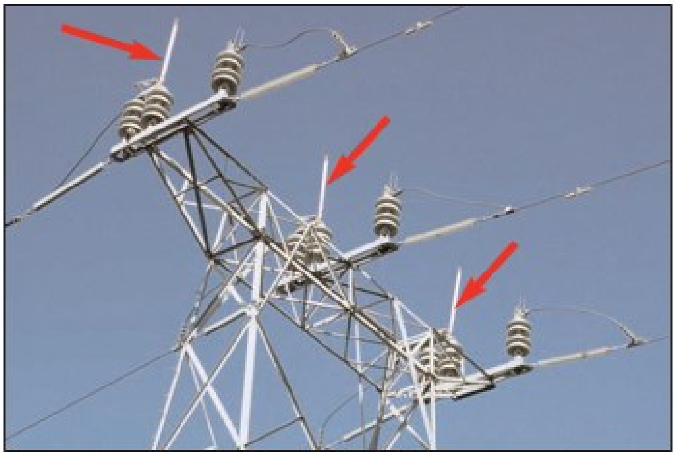


Figure NE-43: Transmission Air Switches Tower Mounted (open position)

EXEMPT EQUIPMENT PHOTOS

Clearance Not Required

This section contains:

E **Section A Temporarily Exempt**

E **Section B Permanent Exempt**

Exempt Equipment Table

Hardware Name/Description	Vendor or CCR Applicable to Exemption	Temporary Exemption Date	Permanent Exemption Date	Pages
Fire Protection Disconnector (used with Hubbell Arrestor)	Hubbell	4/23/2020	-	77
Fuse Saver	Siemens	4/16/2020		78
Linescope for use on circuits up to 115 Kv	Cleaveland Price	12/1/2018	-	79
Clampstar Shunt	Classic Connectors	6/23/2020	-	79
TripSaver II Cutout Mounted Recloser	S&C Electric	1/14/2019	-	80
Current Limiting Non-Expulsion Fuse	Title 14 CCR 1255 (10)	-	5/8/1989	81-82
Liquid Filled Fuse	Title 14 CCR 1255 (8)	-	5/11/1983	83-84
Energy Limiting Fuse (ELF) – Family of Fuses	Eaton-Cooper Fuses	4/26/2004	6/3/2005	85
SMU-20 Fuses **Type-CMU Fuse** **Type-DBU Fuse**	S&C Electric/ Westinghouse/Eaton-Cooper	8/18/1994	-	86
Fault Tamer Fuses	S&C Electric	-	5/8/1989	87
600 AMP Air Switch (does not apply in SDGE service territory)	KPF	8/18/1994	-	88-89
Underarm Side Break Switch 600 & 900 Amp	Eaton-Cooper	6/15/1999	-	90
S&C Omni-Rupter Side Break Switch	S&C Electric	1/4/2000	-	91-93
Scada-Mate Switch	S&C Electric	6/15/1999	-	94
27 kV Line Boss Side Break Switch	Inertia	8/1/2003	-	95
In-Line and Solid Blade Disconnects (exempt only with reclosers, Sectionalizers, and Voltage Regulators)	Title 14 CCR 1255 (7)	-	5/11/1983	96
Sectionalizer	Title 14 CCR 1255 (8)	-	5/11/1983	97

Hardware Name/Description	Vendor or CCR Applicable to Exemption	Temporary Exemption Date	Permanent Exemption Date	Pages
Parallel Groove Connector/GA9000	Title 14 CCR 1255 (3)	-	5/11/1983	101-102
Hot Tap Clamps (some hot tap clamps are Non-Exempt)	Utilco	3/29/1995	-	103
Piercing Hot Tap Clamp	Title 14 CCR 1255 (5)	-	5/11/1983	104
Tree Wire Tie Wire	Title 14 CCR 1255 (5)	-	5/11/1983	105
Idle Split Bolt Connectors (only exempt when idle on the line)	Title 14 CCR 1255 (1)	-	5/11/1983	106
Wedge Connectors	Title 14 CCR 1255 (6)	-	5/11/1983	107
Compression Connectors	Title 14 CCR 1255 (1)	-	5/11/1983	108
Bolted Flat Plate Connector (installed with not less than two bolts)	Title 14 CCR 1255 (6)	-	5/11/1983	109
Automatic Dead-End	Title 14 CCR 1255 (2)	-	1/1/1977	110
Splices (compressed, automatic, and mechanical splices)	Title 14 CCR 1255 (1) (2)	-	1/1/1977	111-112
15kV & 25kV Type 3EK4 surge arresters with (APS) and visible fault indicator	Siemens	9/10/2014	8/25/2017	113
Surge Arrestor with SPU rated 10kA IEC Class I & II 44kV and below	ABB, Inc.	4/10/2017	9/10/2018	114
Sealed & Liquid Filled Reclosers	Title 14 CCR 1255 (8)	-	5/11/1983	115

E Section A: Temporarily Exempt

Hubbell FPD (Fire Protection Disconnector)

Figure A-1 Hubbell Fire Protection Disconnector Attached to Hubbell Surge Arrestor

Ⓔ Fusesavers

Figure A-2: Fusesaver with in-line solid blades Arm Mounted Cutout

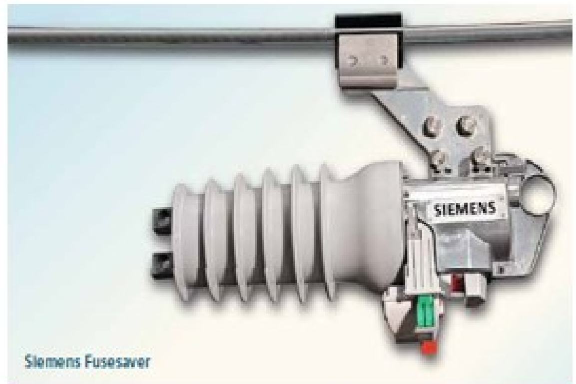


Figure A-3: Siemens Fusesaver

Figure A-4: Conductor Mounted Fusesaver with in-line solid blades

E Monitoring Devices

Figure A-5: Cleaveland Price Linescope for use on circuits up to 115 kV

Shunts

Figure A-6: Classic Connectors' Clampstar Mechanical Shunt

E Reclosers

Figure A-6: Trip Saver II Cutout mounted single phase recloser

Figure A-7: Trip Saver II Cutout mounted single phase recloser with vacuum fault-interrupter

Section B: Permanently Exempt

Non-Expulsion Fuse

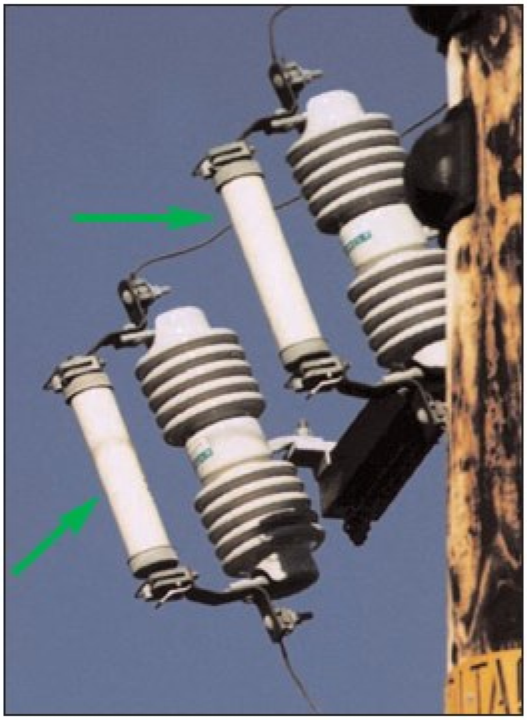


Figure B-1: Arm Mounted Cutout with Non-Expulsion Fuse

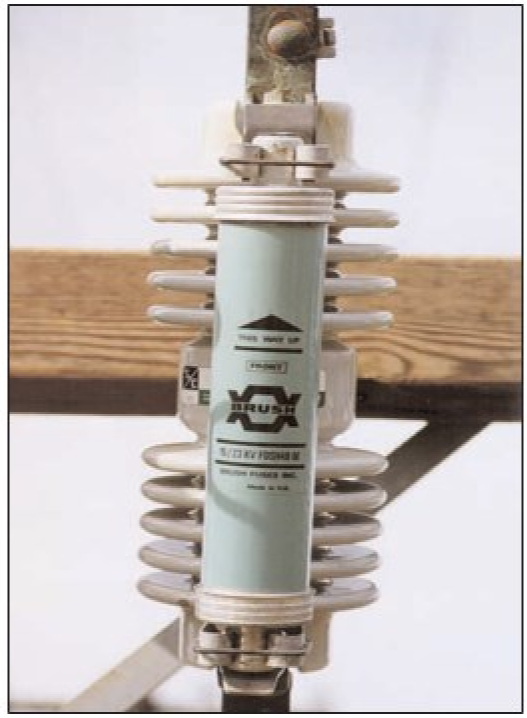


Figure B-2: Arm Mounted Cutout with Non-Expulsion Fuse

Figure B-3: Arm Mounted Cutout with Non-Expulsion Fuses

Non-Expulsion Fuse

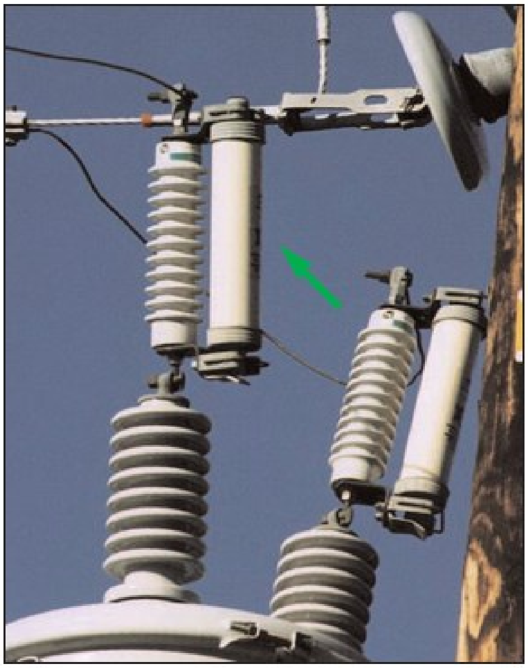


Figure B-4: Bushing Mounted Cutout with Non-Expulsion Fuse

Figure B-5: Hi-Tech Ext/Eaton Cooper Companion II Bushing Mounted Current-Limiting Fuse

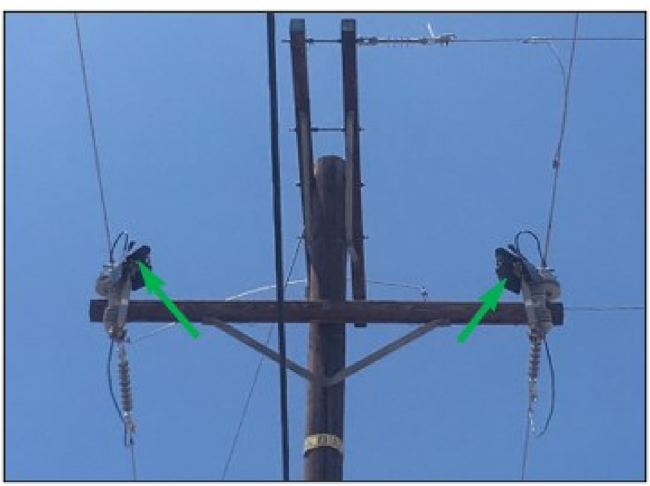


Figure B-6: Eaton Cooper X-Limiter Current-Limiting Fuse

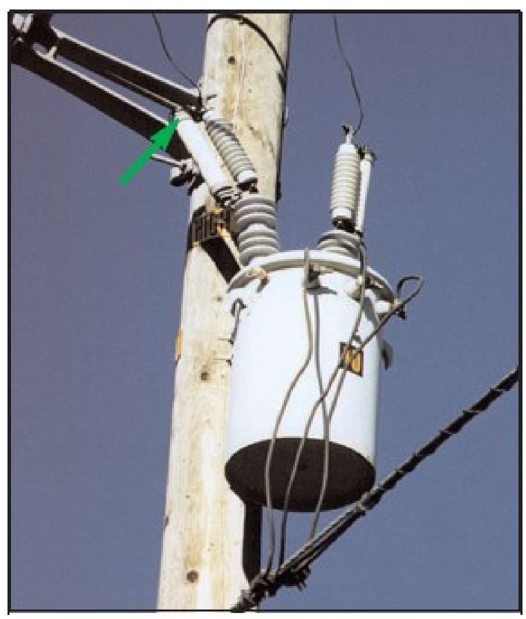


Figure B-7: Bushing Mounted Cutout with Non-Expulsion Fuses

E Liquid Filled Fuse

Figure B-8: Arm Mounted Cutout with Liquid Filled Fuse

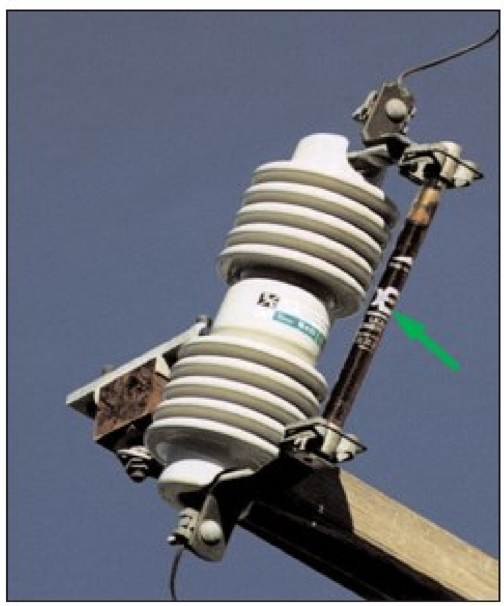


Figure B-9: Liquid Filled Fuse

E Liquid Filled Fuse

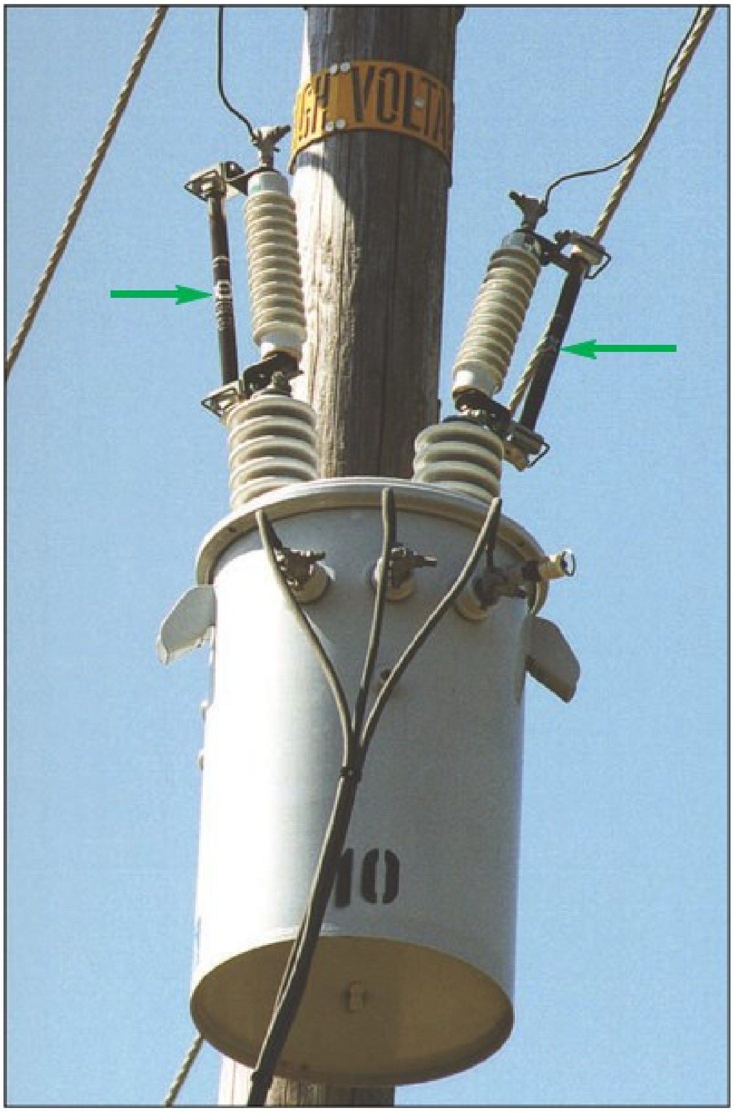


Figure B-10: Over Head Conventional Transformer with Bushing Mounted Cutout and Liquid Filled Fuse

Figure B-11: Liquid Filled Fuse

Energy Limiting Fuse (ELF)

Figure B-12: Also Fits "Open Link" Cutouts

Figure B-13: Also Fits "Clip Style" Cutouts

Figure B-14: Available in 11 1/2" and 8" sizes

Figure B-15: Fault Indicator Cap Indicator Orange Ban under Blue Cap

E Fuses

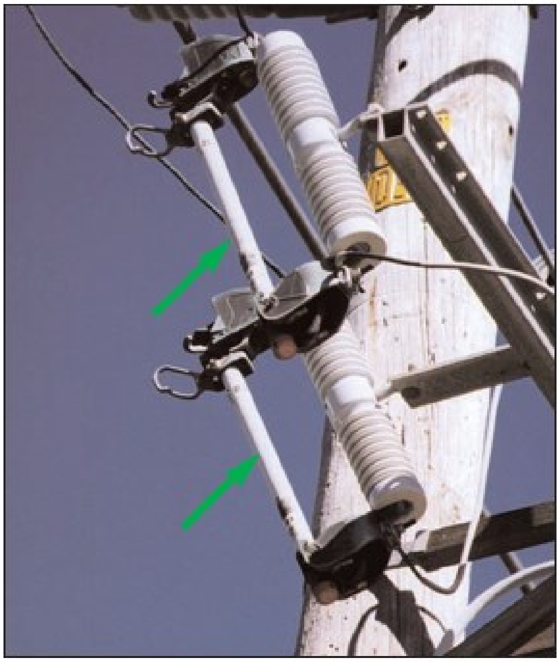


Figure B-16: Arm Mounted Cutout with SMU-20 Fuses

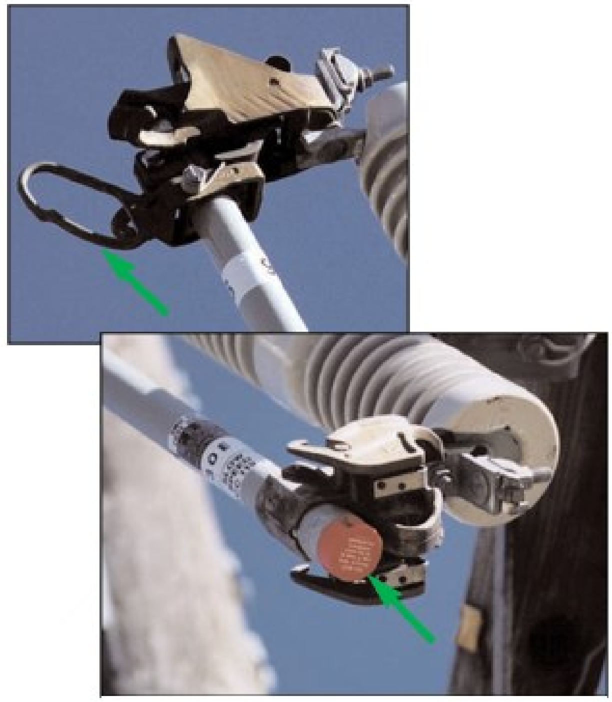


Figure B-17: SMU-20 - Fuse Detail

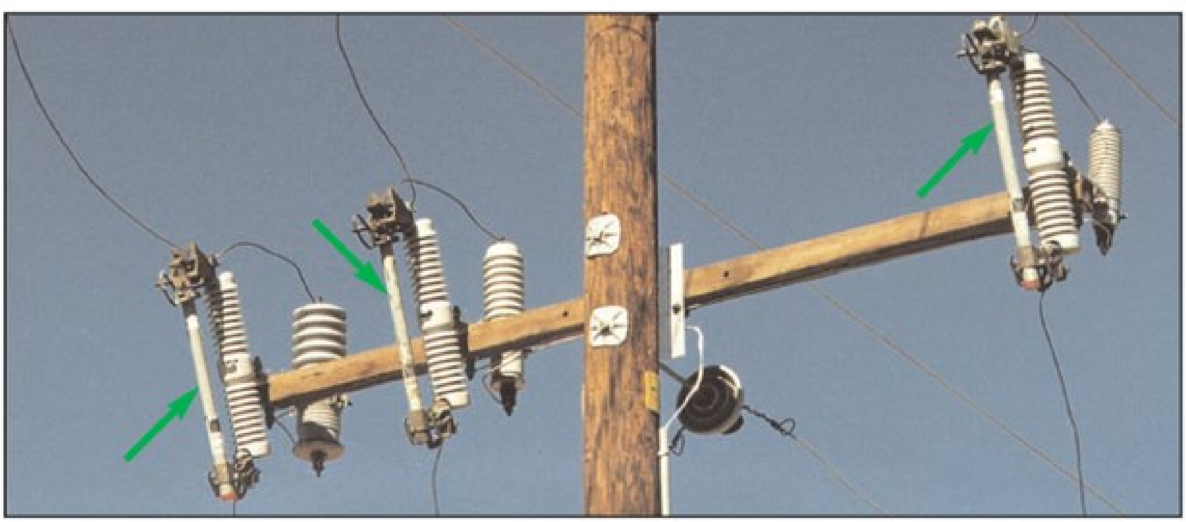


Figure B-18: Arm Mounted Cutout with SMU-20 Fuses

E Fuses

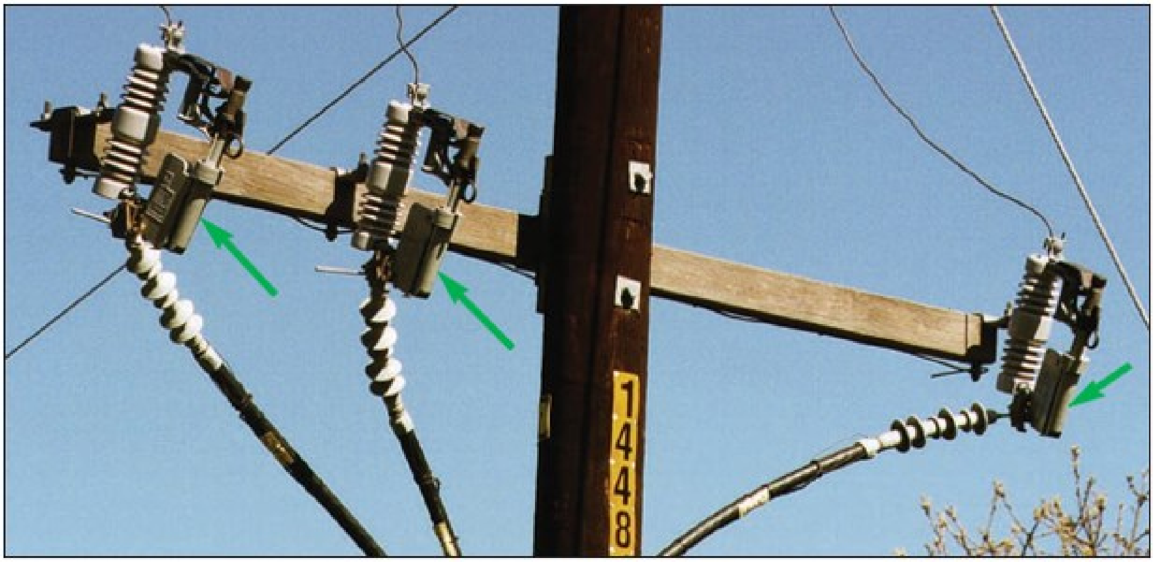


Figure B-19: Arm Mounted Cutout with S&C Fault Tamer Fuse

Figure B-20: S&C Fault Tamer Fuse

Figure B-21: S&C Fault Tamer Fuse (Open)

600 Amp Air Switch

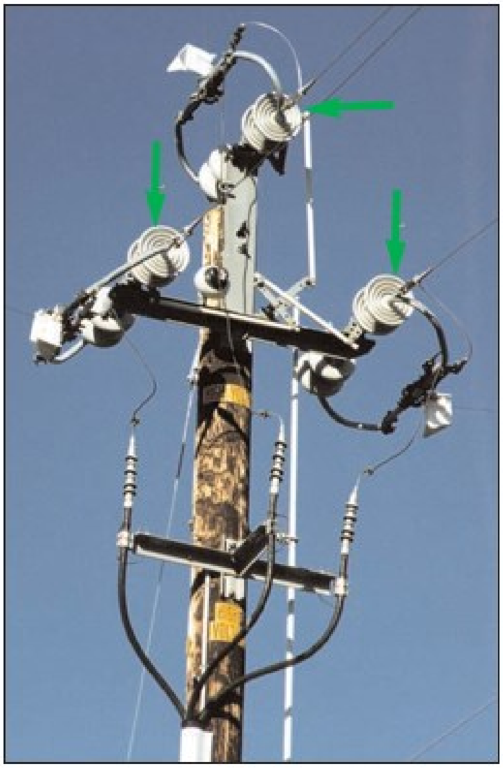
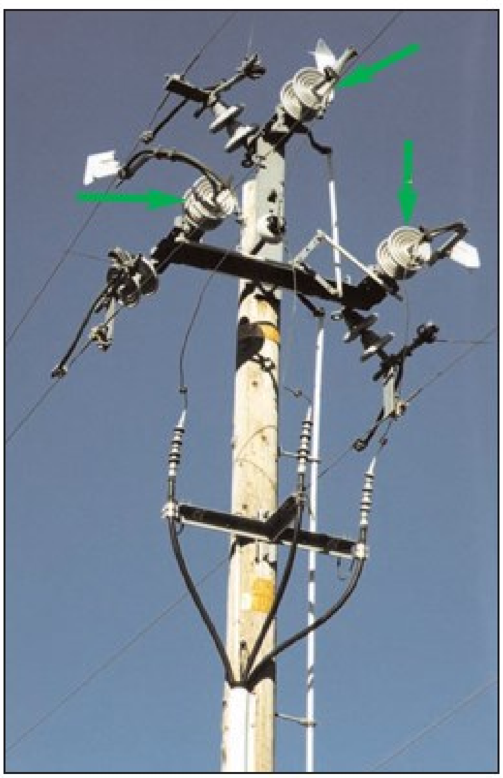


Figure B-22: 600 Amp KPF Air Switch, Triangular Construction (Closed Position

Note: Exemption does not apply in SDG&E's Service Territory

SDGE

A Sempra Energy utility®



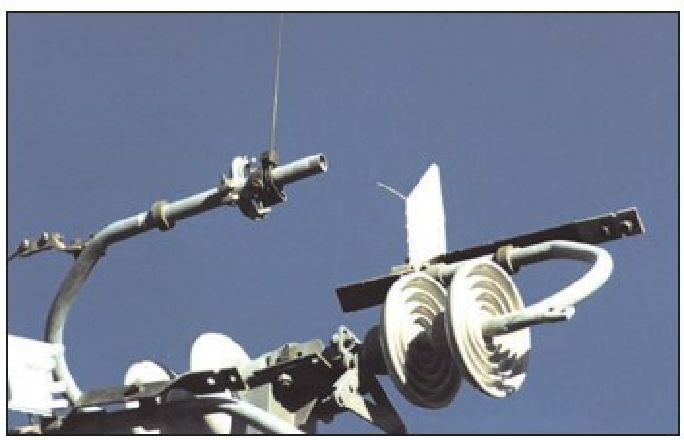


Figure B-23: 600 Amp KPF Air Switch, Triangular Construction (Open Position)

E 600 Amp Air Switch

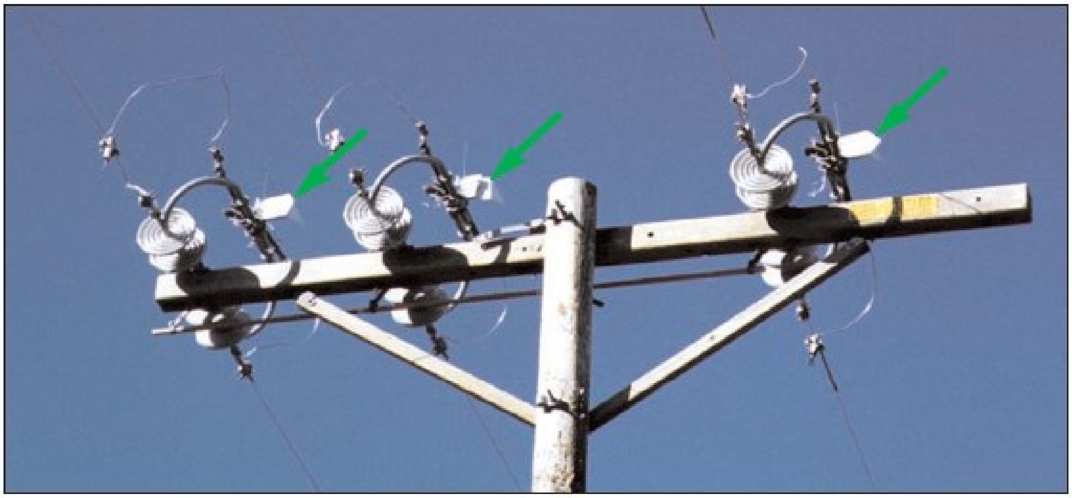


Figure B-24: 600 Amp KPF Air Switch, Crossarm Construction (Closed Position) with Arcing Horns and Snuffers

Note: Exemption does not apply in SDG&E's Service Territory

SDGE
A Sempra Energy utility

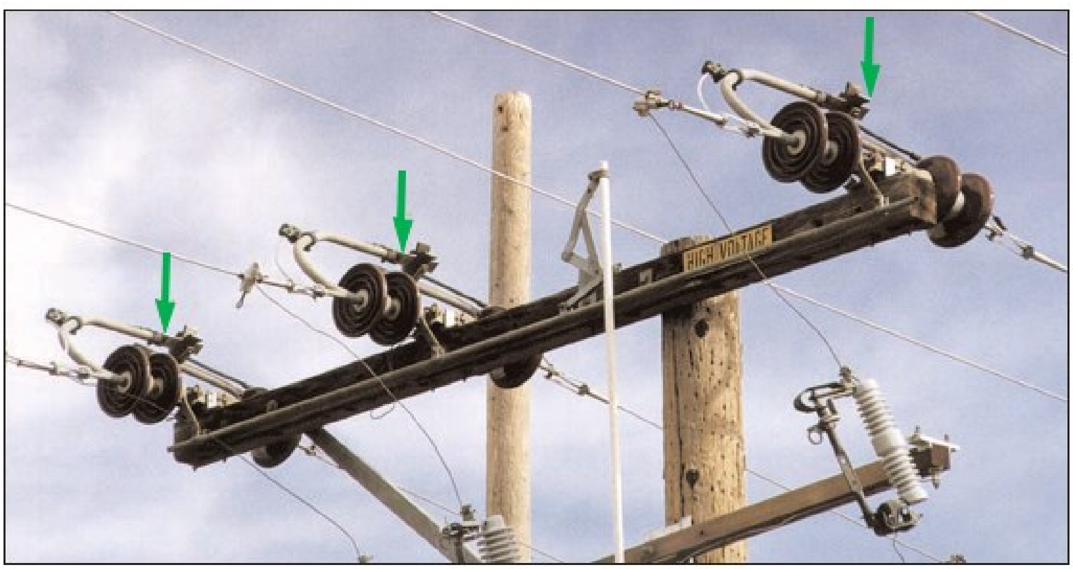


Figure B-25: 600 Amp KPF Air Switch, Crossarm Construction (Closed Position) without Arcing Horns or Snuffers

E Underarm Side Break Switch

Figure B-26: Eaton-Cooper 600 Amp Underarm Side Break Switch (Open Positions)

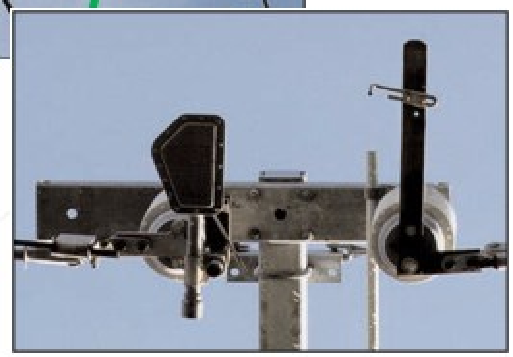


Figure B-27: Open Unit

Figure B-28: Closed Unit

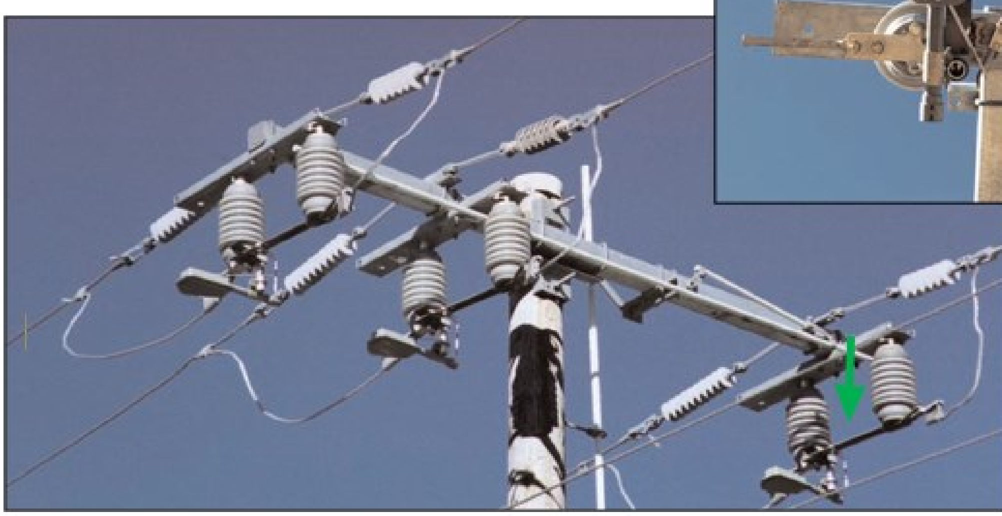


Figure B-29: Eaton-Cooper 600 Amp Underarm Side Break Switch (Closed Position)

Ⓔ Underarm Side Break Switch

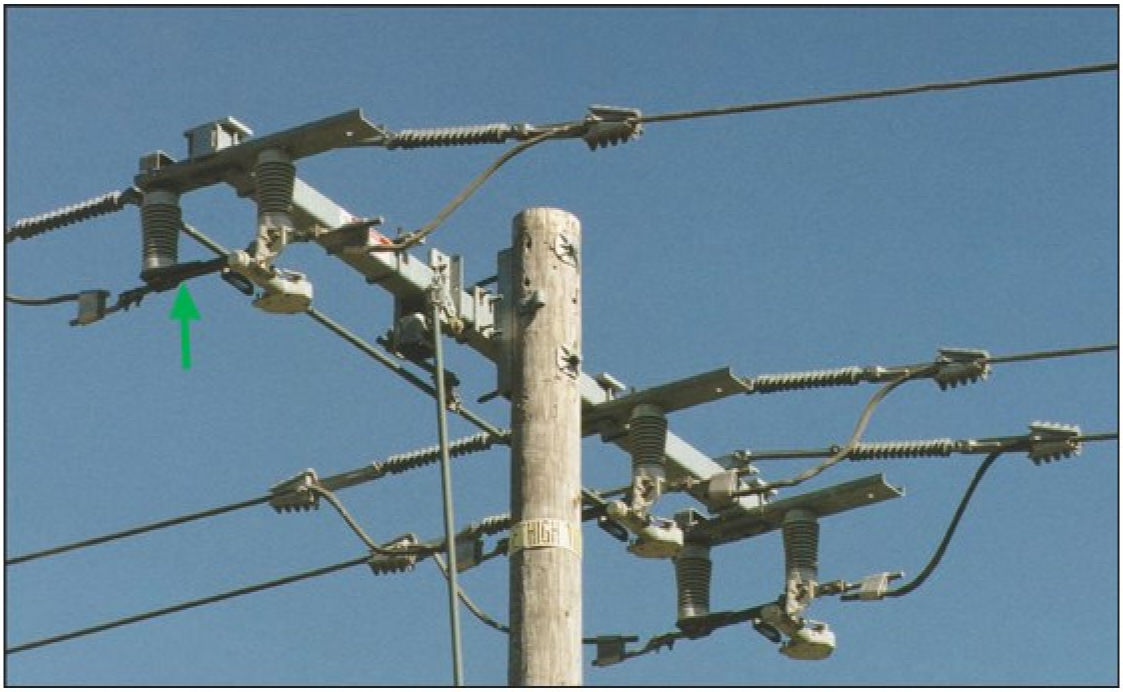


Figure B-30: S&C Omni-Rupter 600 Arm Underarm Side Break Switch (Closed Position)

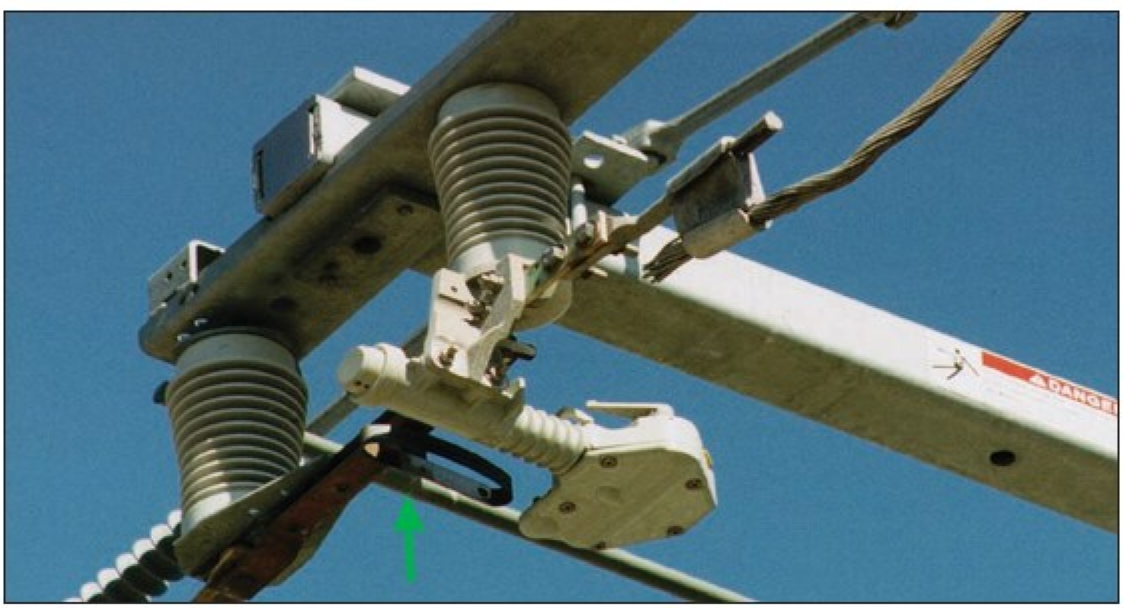


Figure B-31: S&C Omni-Rupter 600 Amp Underarm Side Break Switch (Closed Position)

E Switches

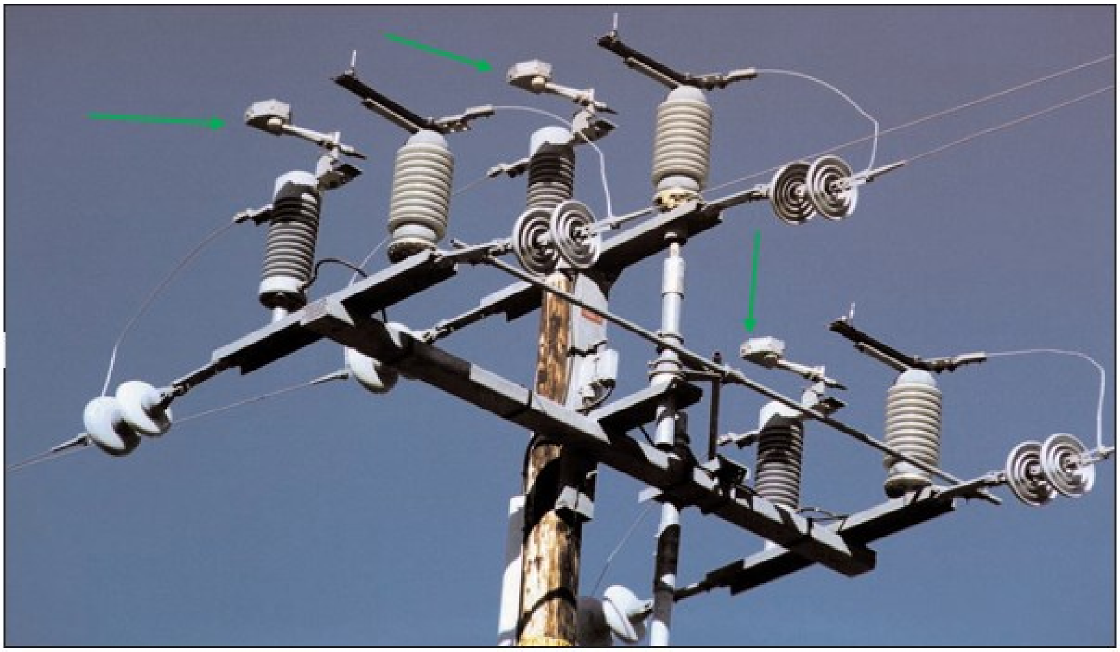


Figure B-32: S&C Omni-Rupter Switch, Triangular Construction (Open Position)

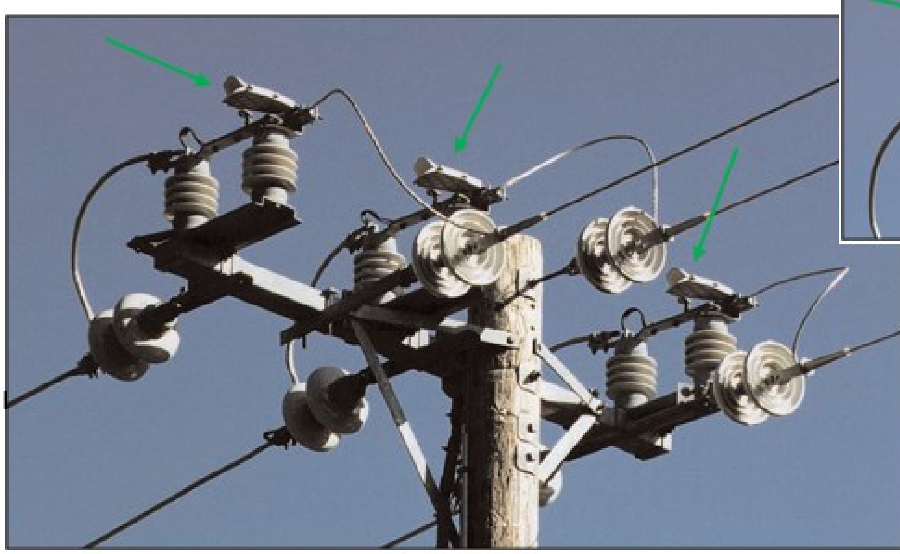


Figure B-33: S&C Omni-Rupter Switch, Tangent Construction (Closed Position)

Figure B-34: Closed Unit

Switches

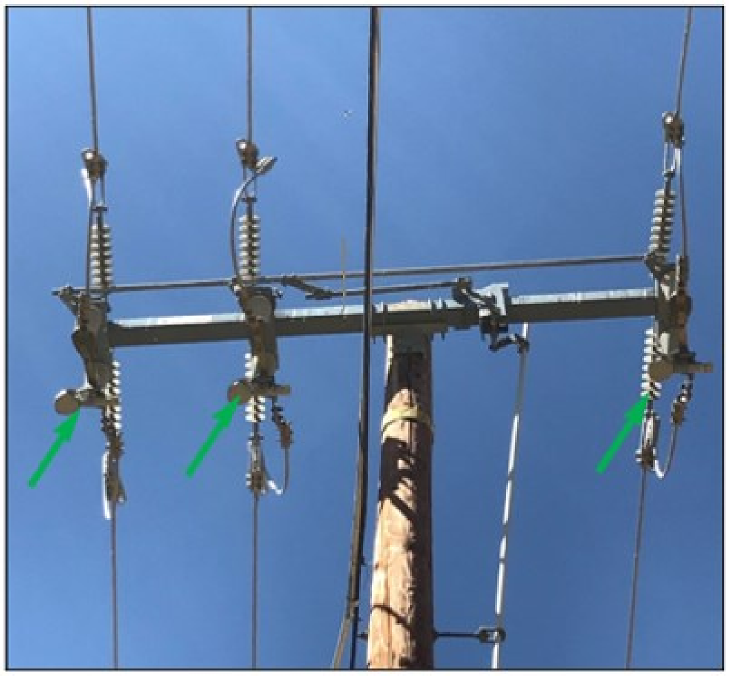


Figure B-35: S&C Omni-Rupter Horizontal Crossarm Invertered Switch

Figure B-36: S&C Omni-Rupter Switch in Riser Configuration

E Switches

Figure B-37: S&C Scada-Mate Switch

Figure B-38: Open Position Indicator Green Letter "O"

Figure B-39: Closed Position Indicator Red

E Switches

Figure B-40: 27kV Inertia Line-Boss Underarm Side Break Switch (Closed Position)

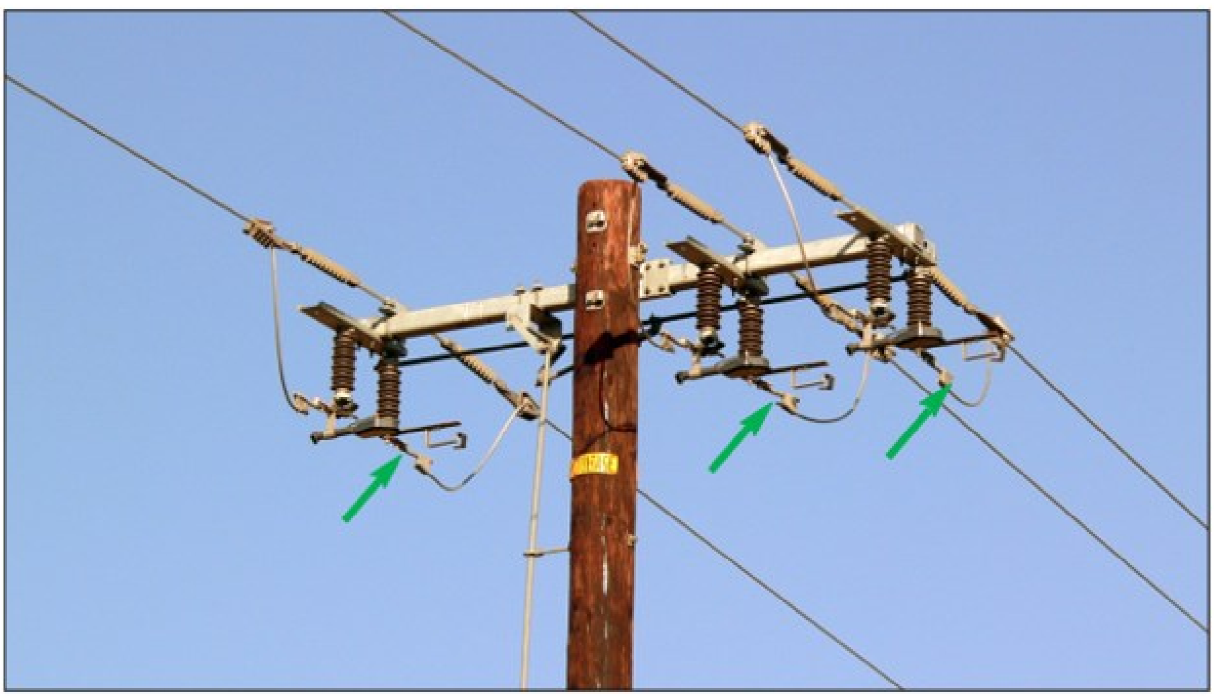


Figure B-41: 27kV Inertia Line-Boss Underarm Side Break Switch

E Disconnects

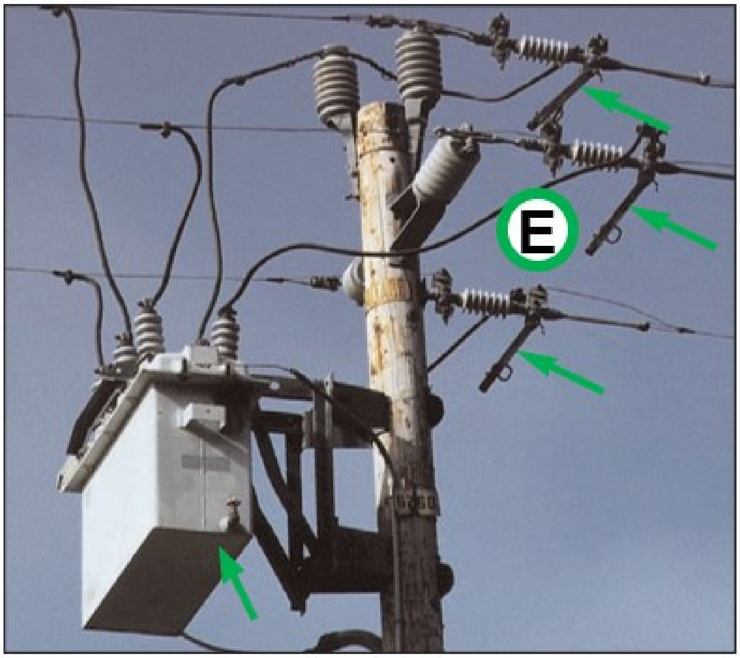


Figure B-42: Recloser with In-Line Disconnects (Open Position)

E

In-Line Disconnects and Solid Blade Disconnects are exempt.
Note: Only when used with Reclosers, Sectionalizers (B-42 – B-47) or Voltage Regulators (B-48).

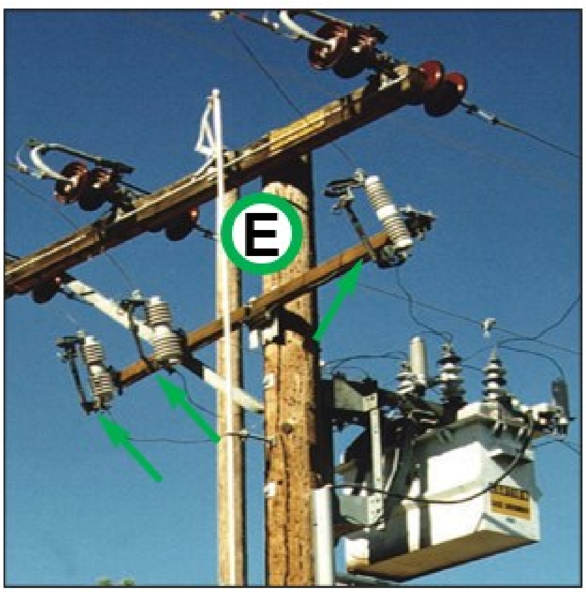


Figure B-43: Recloser with Solid Disconnects (Closed Position)

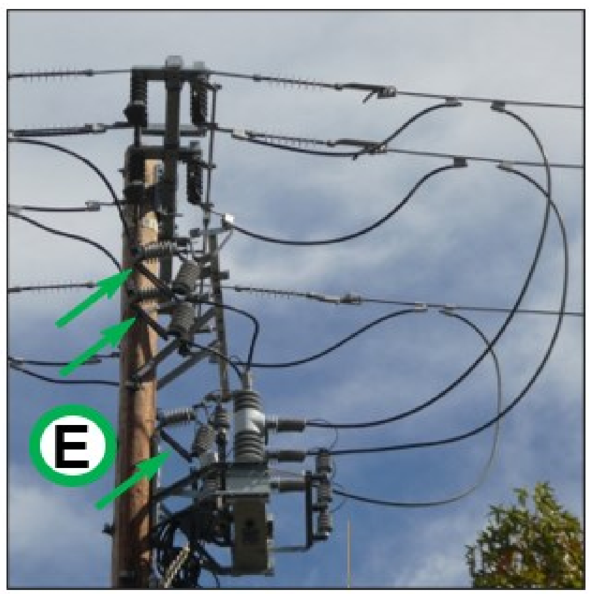


Figure B-44: Recloser with Solid Blade Disconnects

Ⓔ Sectionalizers

Figure B-45: Sectionalizer with Solid Blade Disconnects

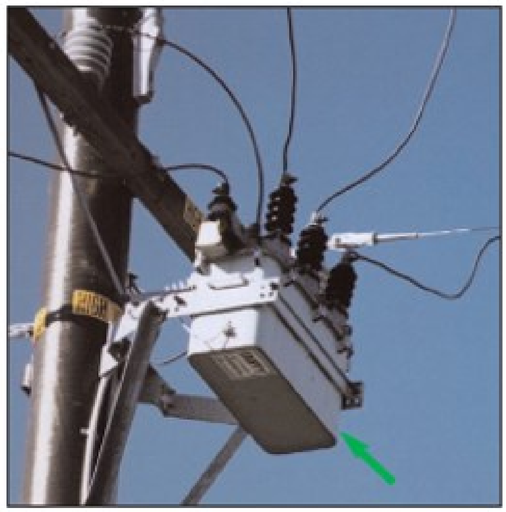


Figure B-46: Sectionalizer

Ⓔ **In-Line Disconnects and Solid Blade Disconnects are exempt.**
Note: Only when used with Reclosers, Sectionalizers (B-42 – B-47) or Voltage Regulators (B-48).

Figure B-47: 600A Disconnect. It is non-exempt equipment as part of recloser installation

Ⓔ Voltage Regulators

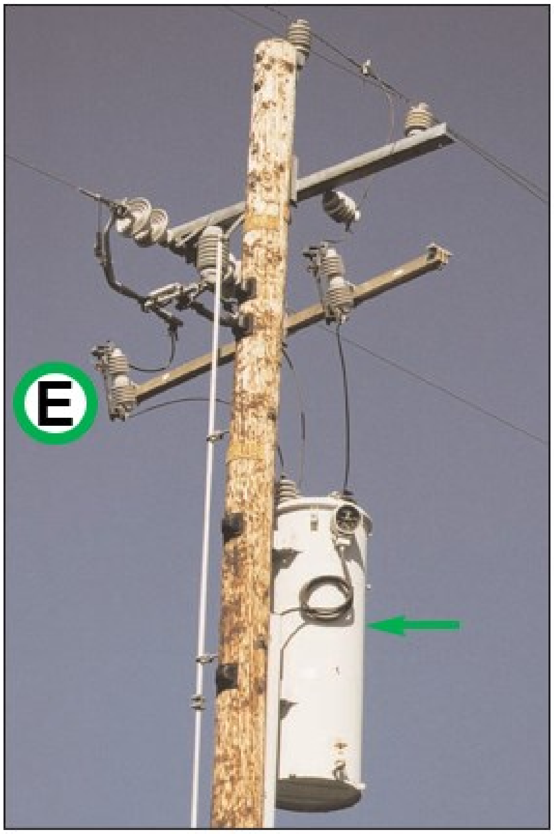


Figure B-48: Voltage Regulator with Solid Blade Disconnects

Ⓔ

In-Line Disconnects and Solid Blade Disconnects are exempt. Note: Only when used with Reclosers, Sectionalizers, or Voltage Regulators (B-42 – B-47)

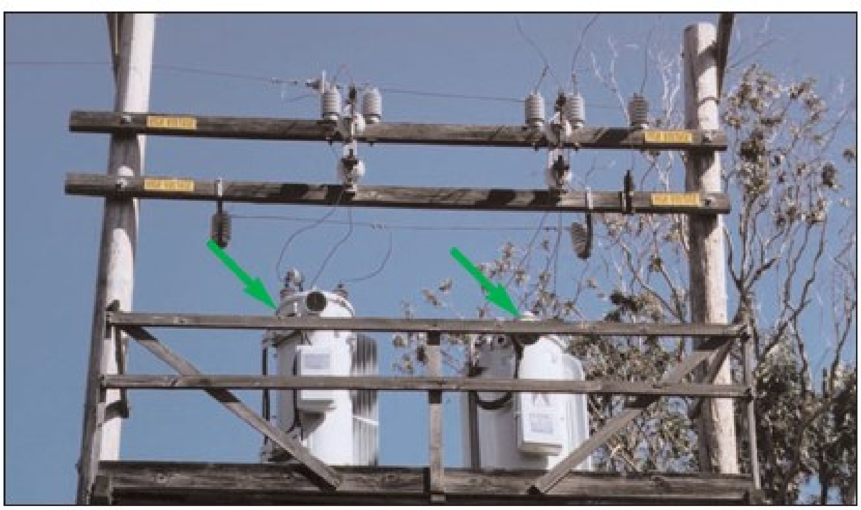


Figure B-49: Voltage Regulator

Ⓔ Capacitor Bank

Figure B-50: Capacitor Bank

Figure B-51: Capacitor Unit

Ⓔ Transformer

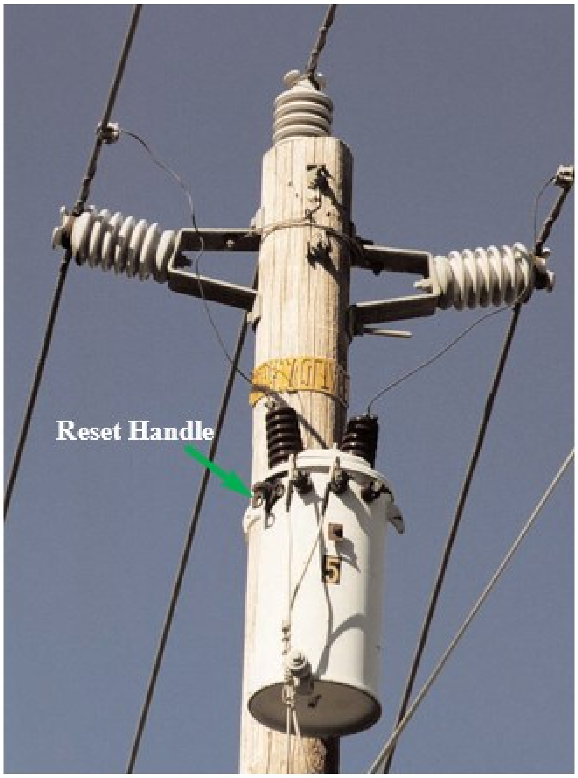


Figure B-52: Self-Protected Transformer (No External Cutouts or Fuses)

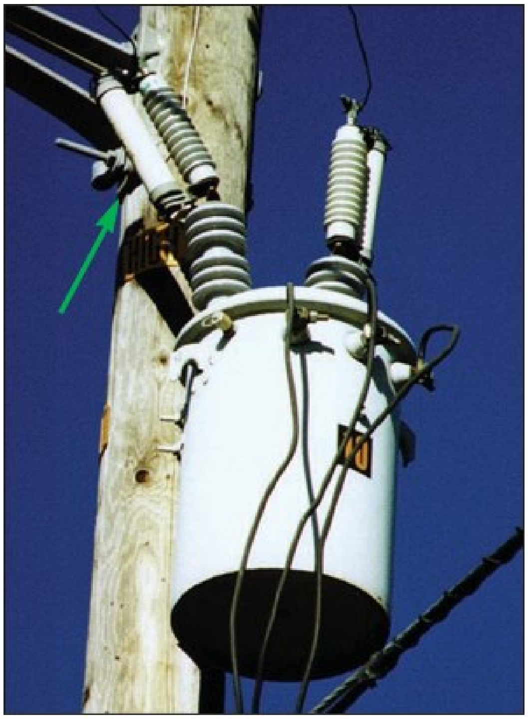


Figure B-53: Conventional Transformer with Exempt Fuses

Ⓔ Parallel Groove Connectors

Figure B-54: Parallel Groove Connectors

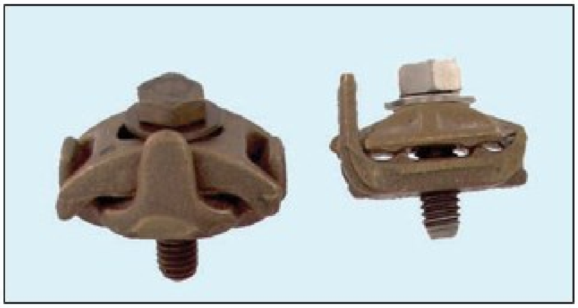


Figure B-55: Copper Parallel Groove Connectors

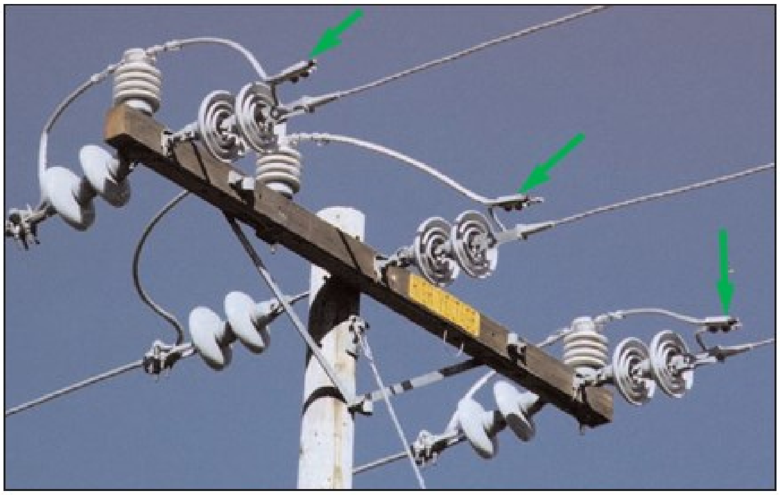


Figure B-56: Parallel Groove Connectors on Jumpers

E Parallel Groove Connectors

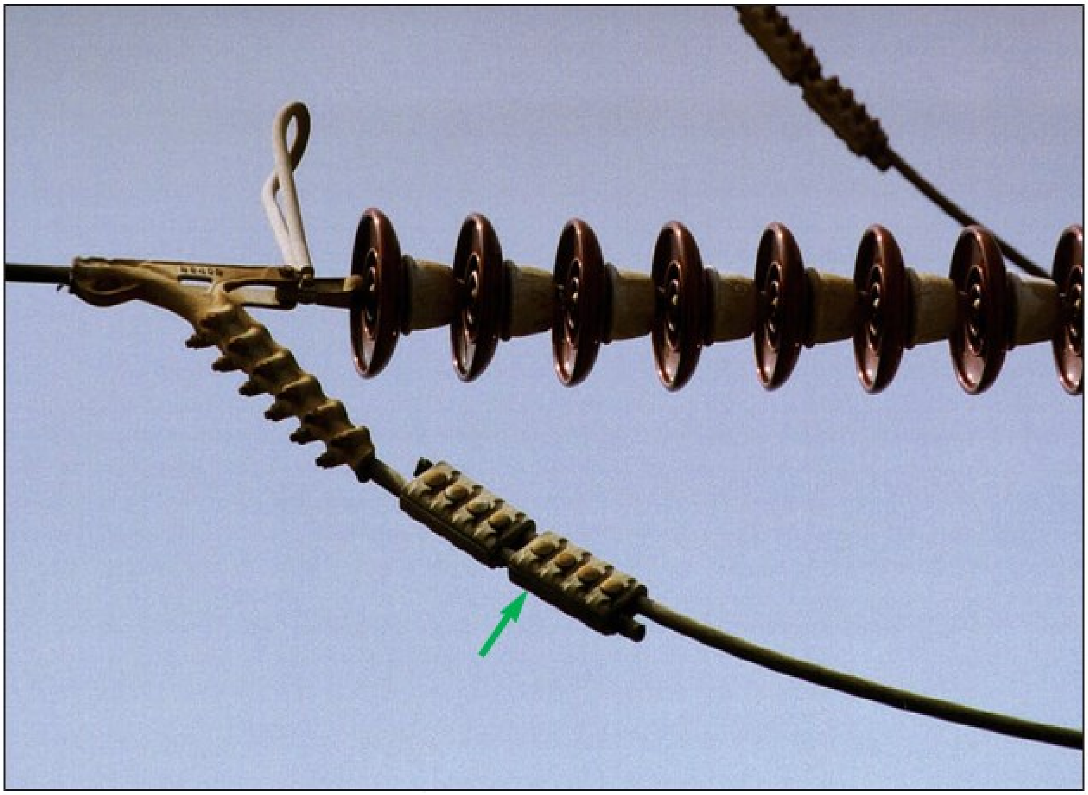


Figure B-57: Transmission Dead-end with Parallel Groove Connectors

GA9000 Parallel Groove Connector on Conductor

GA9000 Parallel Groove Connectors

Ⓔ Hot Tap Clamp

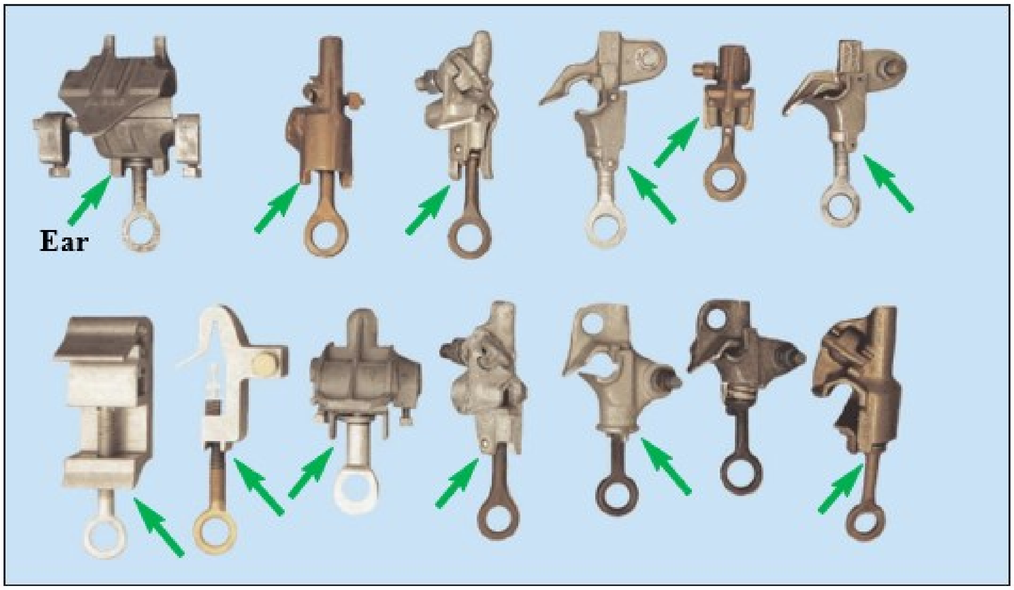


Figure B-58: Hot Tap Clamps

Note: Title 14 CCR 1255 exempts hot line tap or clamp connectors that were designed to absorb any expansion or contraction by applying spring tension on the main line or running conductor and tap connector. Not all Hot Taps are exempt.

Figure B-59: Compare with Non-Exempt Hot Tap Clamps on page 68.

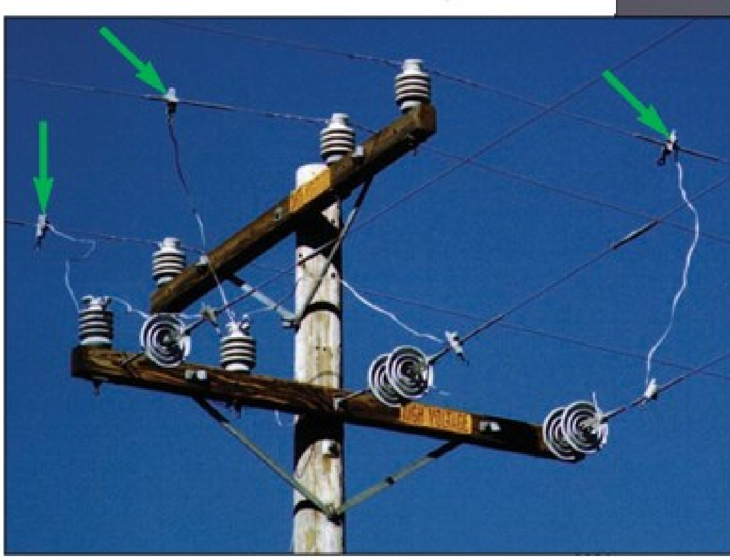


Figure B-60: Hot Tap Clamps on conductor

E Piercing Tap Clamp

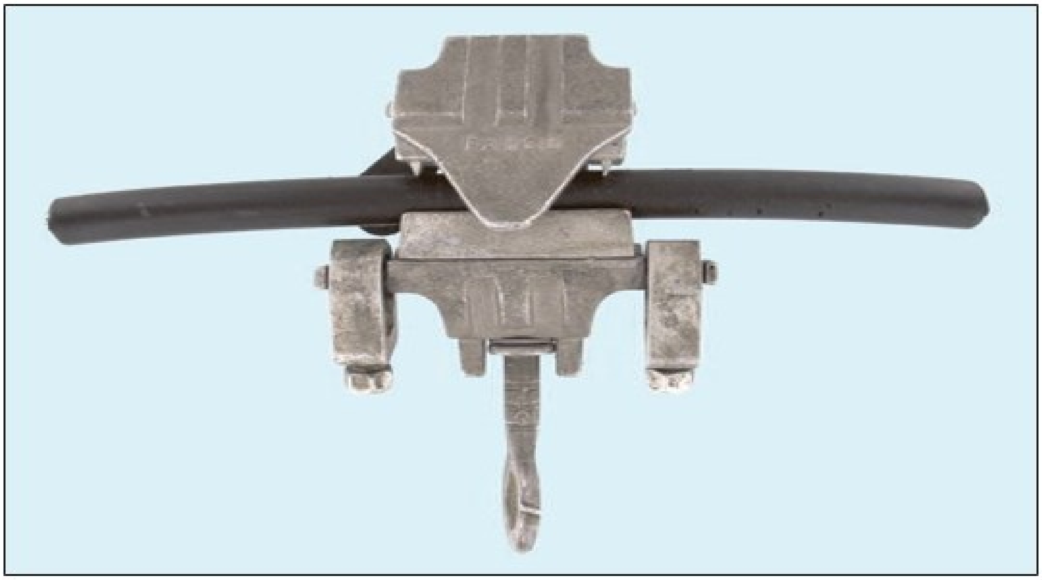


Figure B-61: Piercing Hot Tap Clamp on Tree Wire

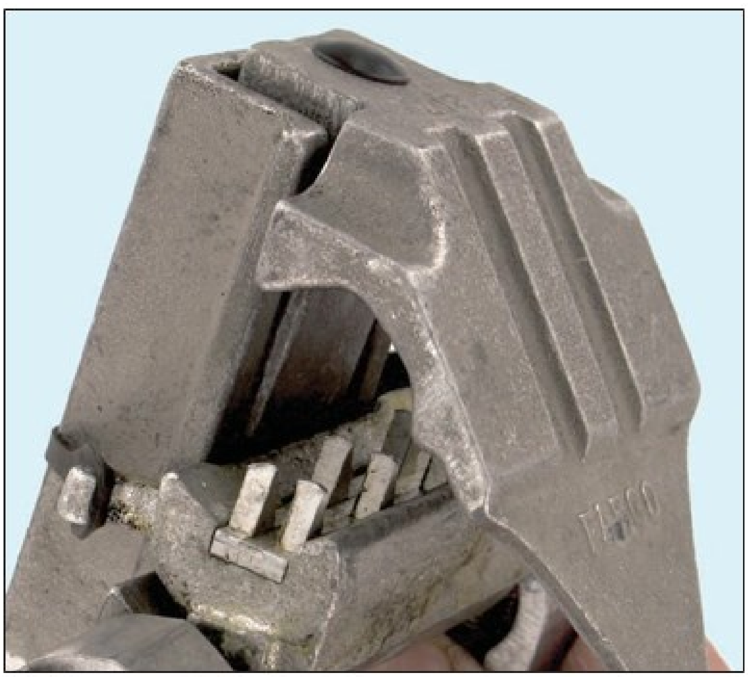
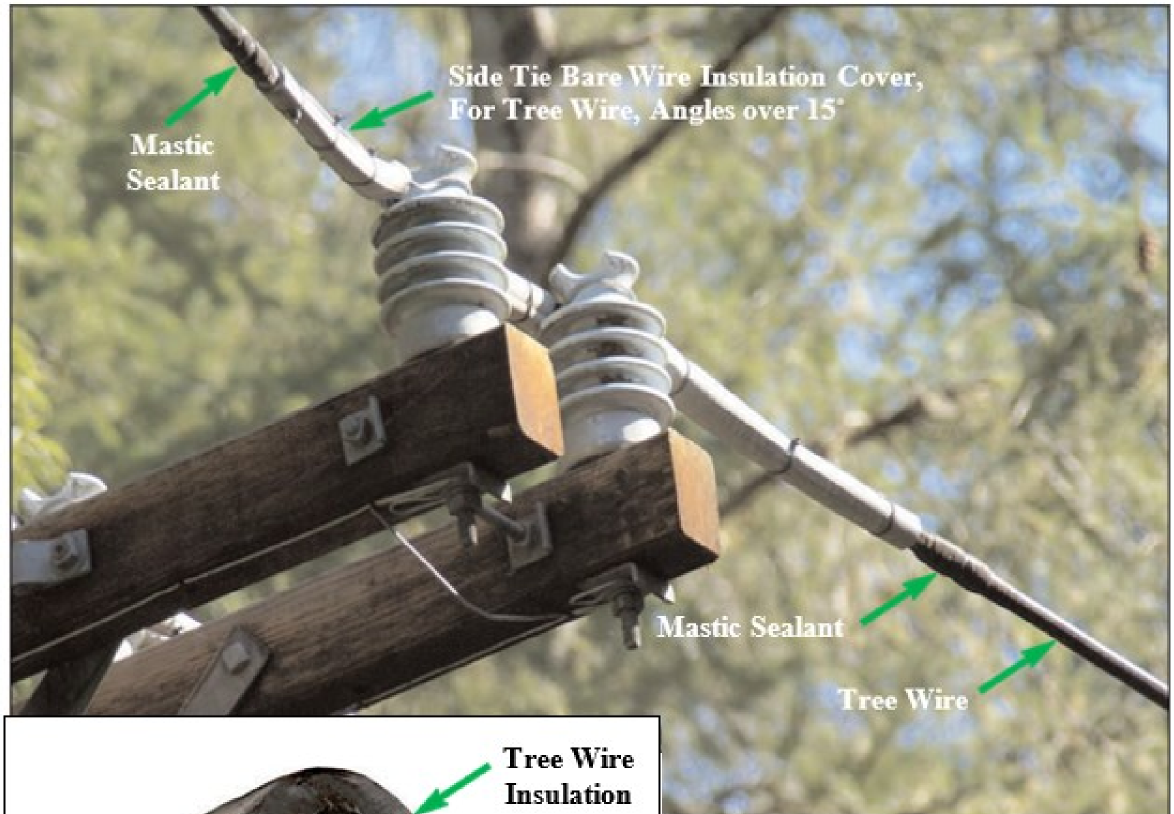


Figure B-62: Piercing Hot Tap Clamp - Detail

Tree Wire



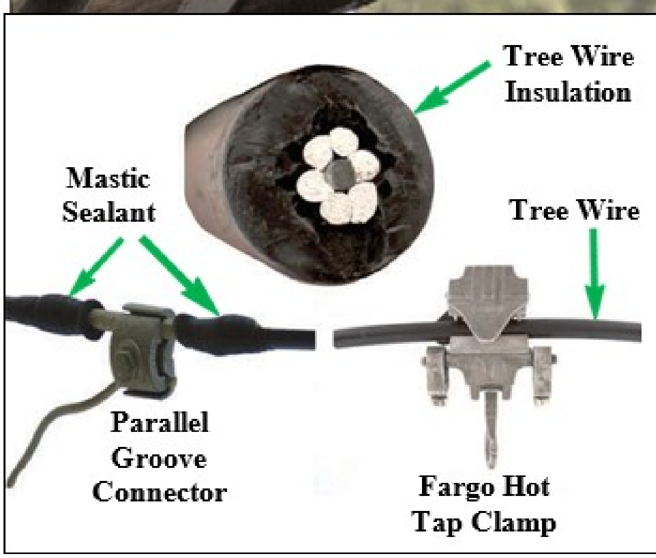


Figure B-63: Tree Wire Detail

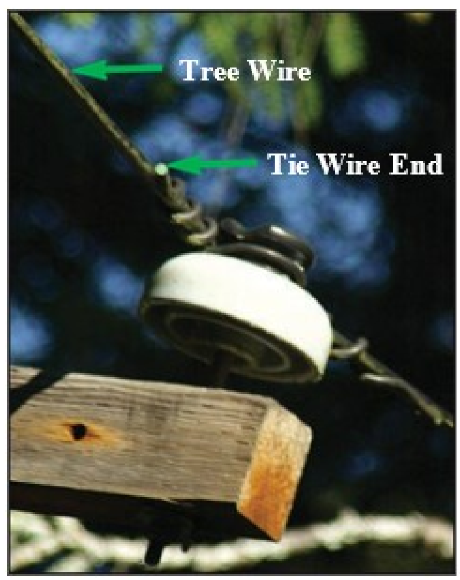


Figure B-64: Tree Wire Tie Wire

E Idle Split Bolt Connectors

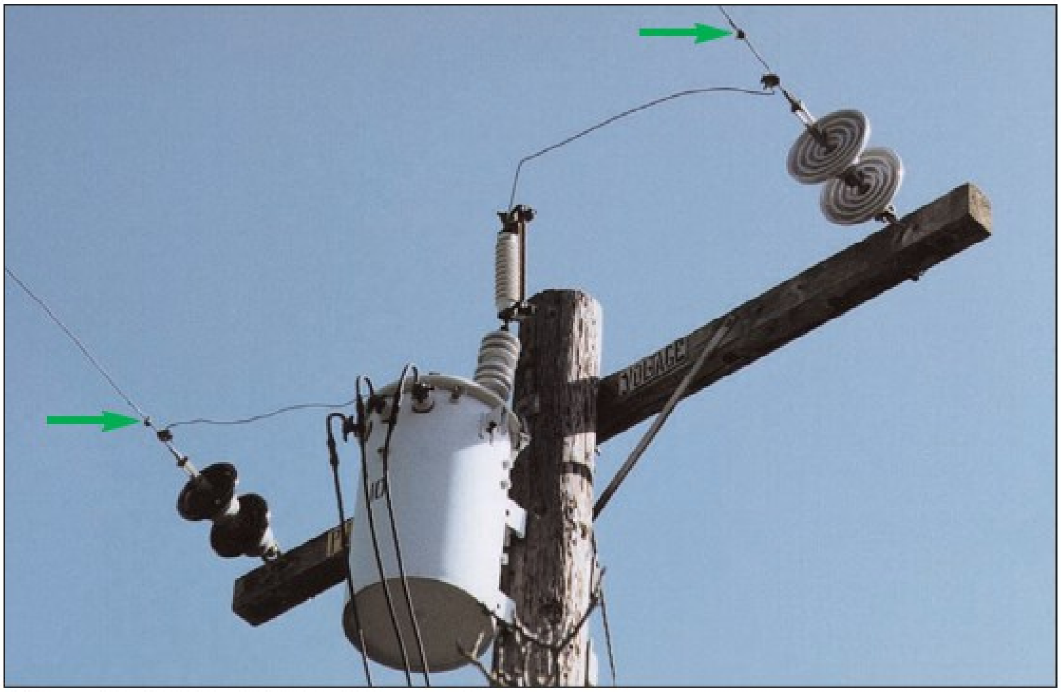


Figure B-65: Idle Split Bolt Connectors

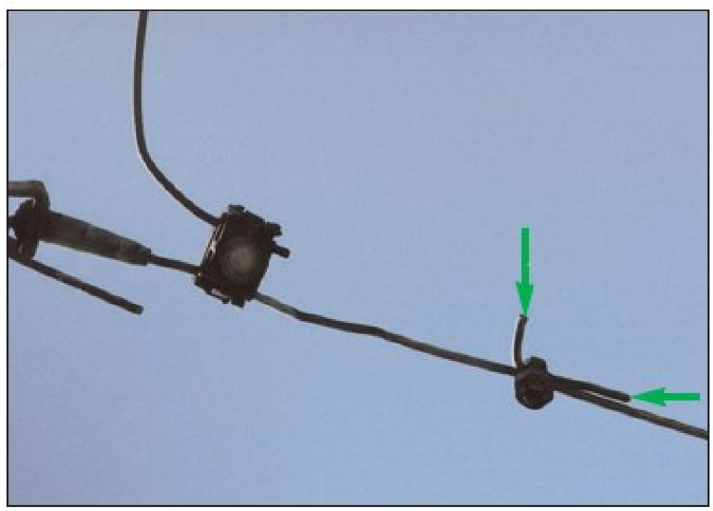


Figure B-66: Close-Up of Non-Exempt Split Bolt and Copper Parallel Groove Connector

Note: Split Bolts are ONLY exempt when idle on the line.
See Figure NE-32 on Page 69 for non-exempt spilt bolts

E Wedge Connectors

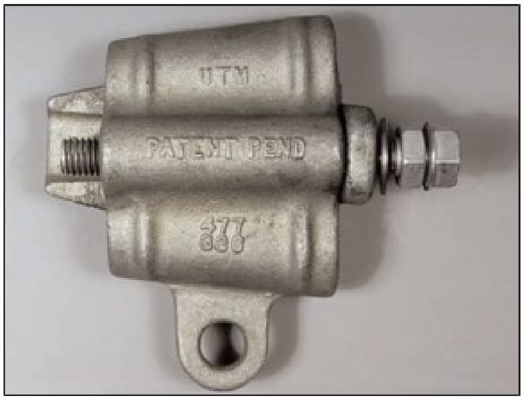


Figure B-67: Bolted Wedge Connector

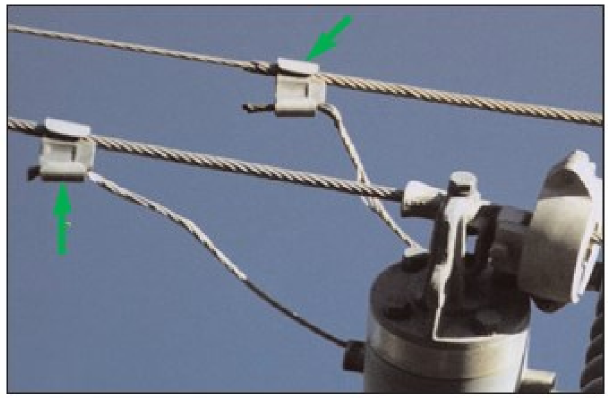


Figure B-68: Fired Wedge Connectors on Line

Figure B-69: Fired Wedge Connectors

Figure B-70: CPI Wedge Connectors

Figure B-71: CPI Wedge Connectors on Line

Ⓔ Compression Connectors

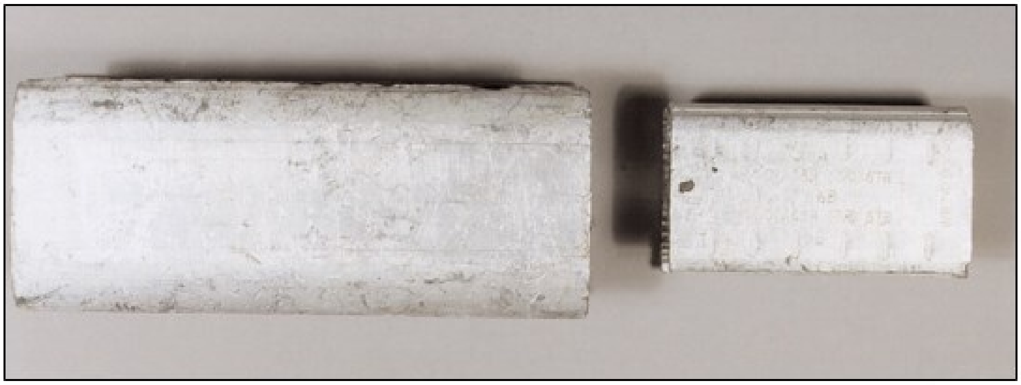


Figure B-72: H-Type Compression Connector (Not Compressed)

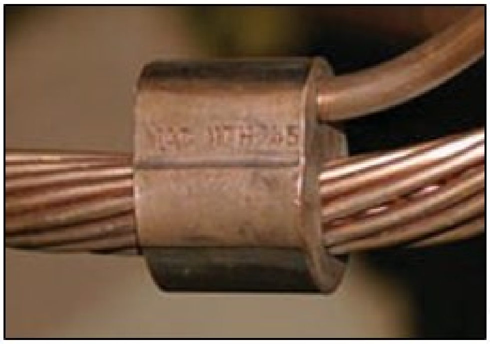


Figure 3B-73: Copper Compression Connector (Compressed)

Figure B-74: H-Type Compression Connector (Compressed)

Ⓔ Bolted Flat Plate Connector

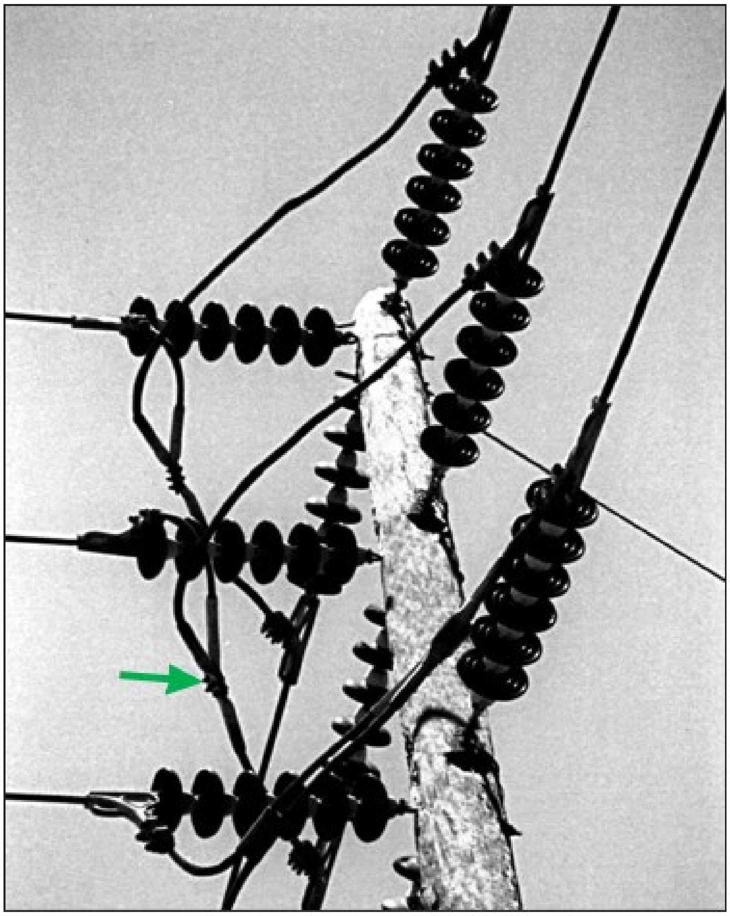


Figure B-75: Transmission Vertical Dead-end with Bolted Flat Plate Connector

Figure B-76: Bolted Flat Plate Connector

Ⓔ Automatic Dead-End

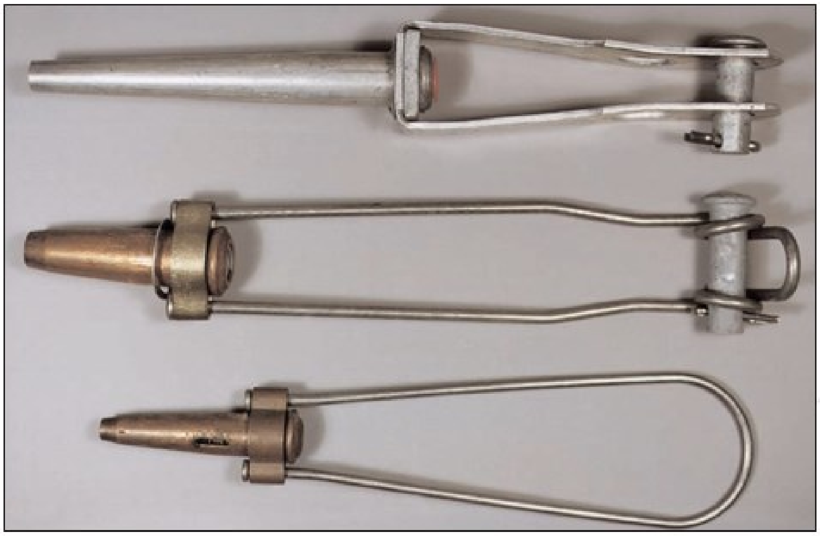


Figure B-77: Automatic Dead-end

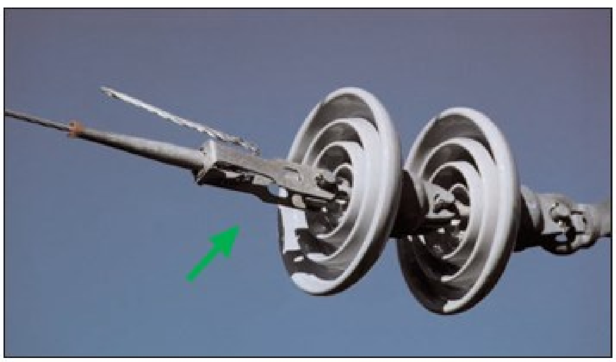


Figure B-78: Automatic Dead-ends with Suspension Insulators

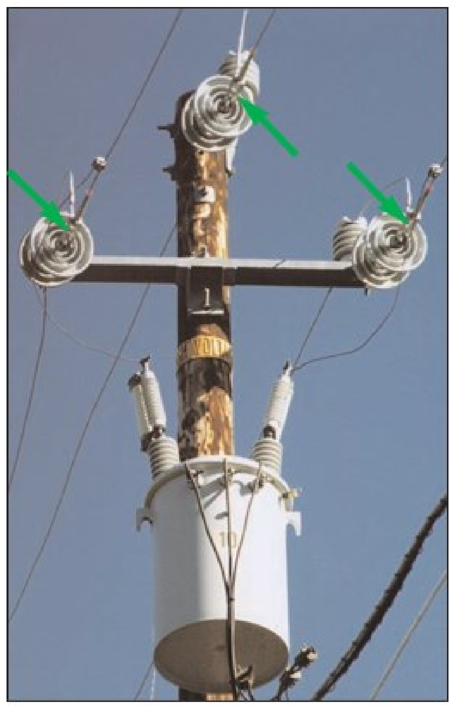


Figure B-79 Automatic Dead-ends Attached to Pole and Crossarm

Ⓔ Splices

Note: If there are 3 or more splices per conductor on a span (between 2 poles), notify the utility company to check the line.

Figure B-80: Line Splices

Figure B-81: Compressed Line Splice

Figure B-82: Compressed Line Splice

Figure B-83: Automatic Line Splices

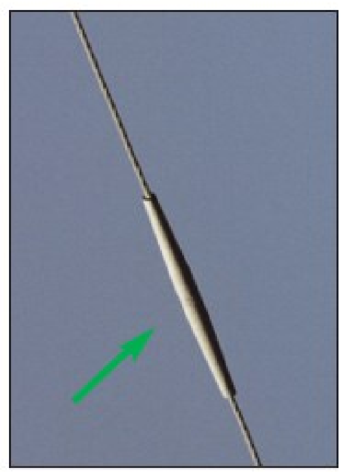


Figure B-84: Automatic Line Splice Installed on Line

E Splices

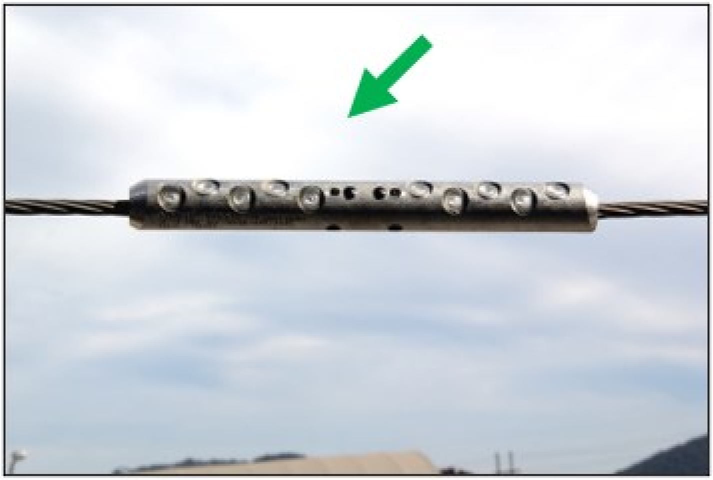


Figure B-85: Mechanical Splice with Engineered Shear Bolts

Ⓔ Lightning (Surge) Arresters

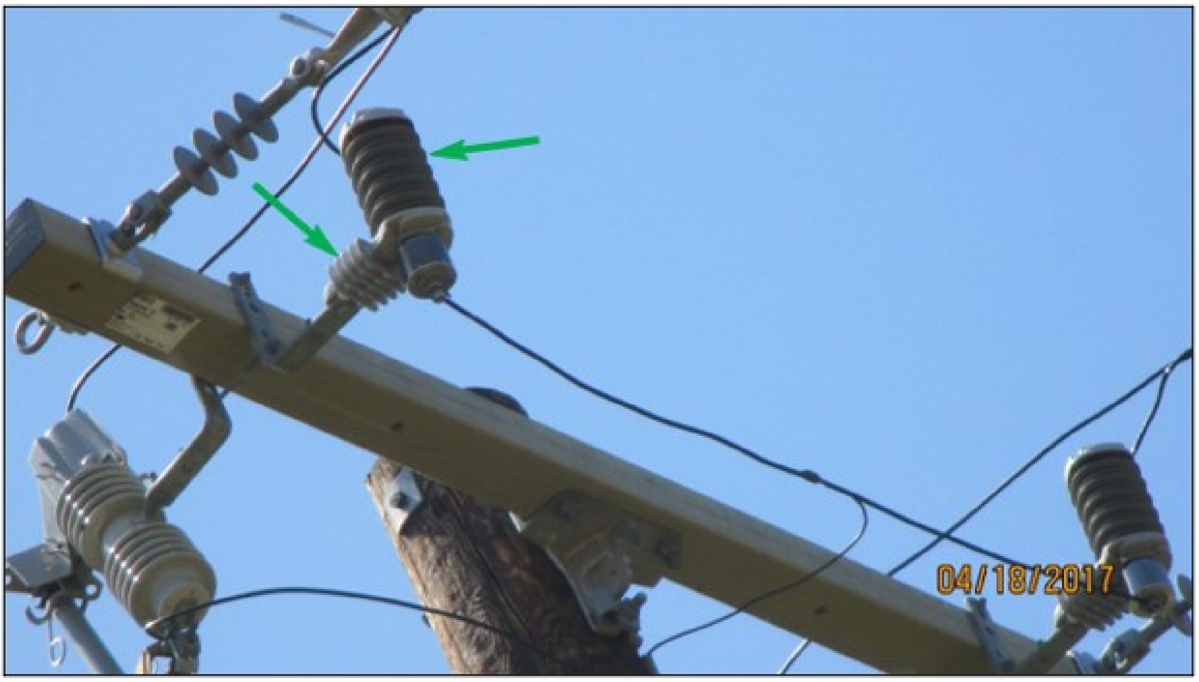


Figure B-86: *Siemens Lightning Arrester*

15 kV and 25 kV Type 3EK4 surge arresters equipped with Arc Prevention Systems (APS) and visible fault indicator

Figure B-87: Siemens Lightning Arrester

15 kV and 25 kV Type 3EK4 surge arresters equipped with Arc Prevention Systems (APS) and visible fault indicator

Ⓔ Lightning (Surge) Arresters

Figure B-88: ABB surge arrester equipped with Spark Prevention Unit (SPU), rated 10kA IEC Class I & II 44 kV and below

E Reclosers

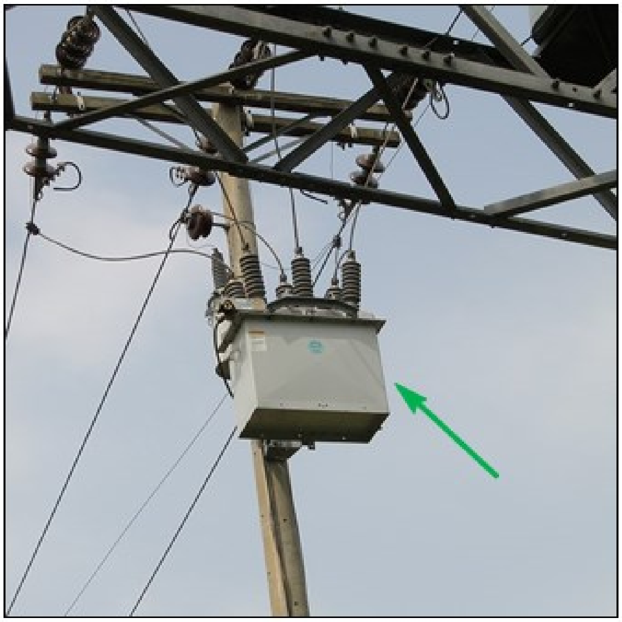


Figure B-90: Oil-Filled Recloser designed for use on overhead electricity distribution networks to detect and interrupt momentary faults.

Figure B-91: Eaton-Cooper RXE/WE Oil Filled Recloser.

POWER LINE CONSTRUCTION (PLC) PHOTOS

The photo captions below have the prefix of "PLC," which stands for "Power Line Construction" in this section.

Distribution Construction

Figure PLC-1: Vertical Angle

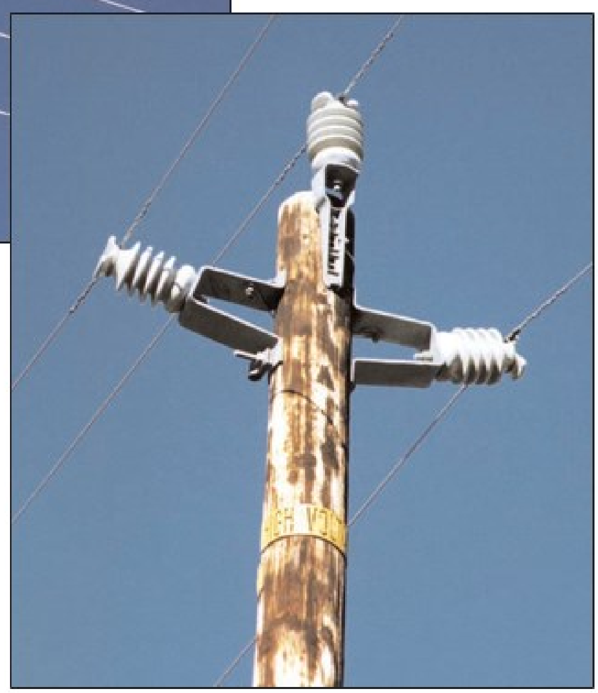


Figure PLC-2: Triangular

Distribution Construction

Figure PLC-3: Alley Arm

Figure PLC-4: Crossarm (Tangent)

Distribution Construction

Figure PLC-5: Tangent Crossarm with Dead-end Tap (T-Tap

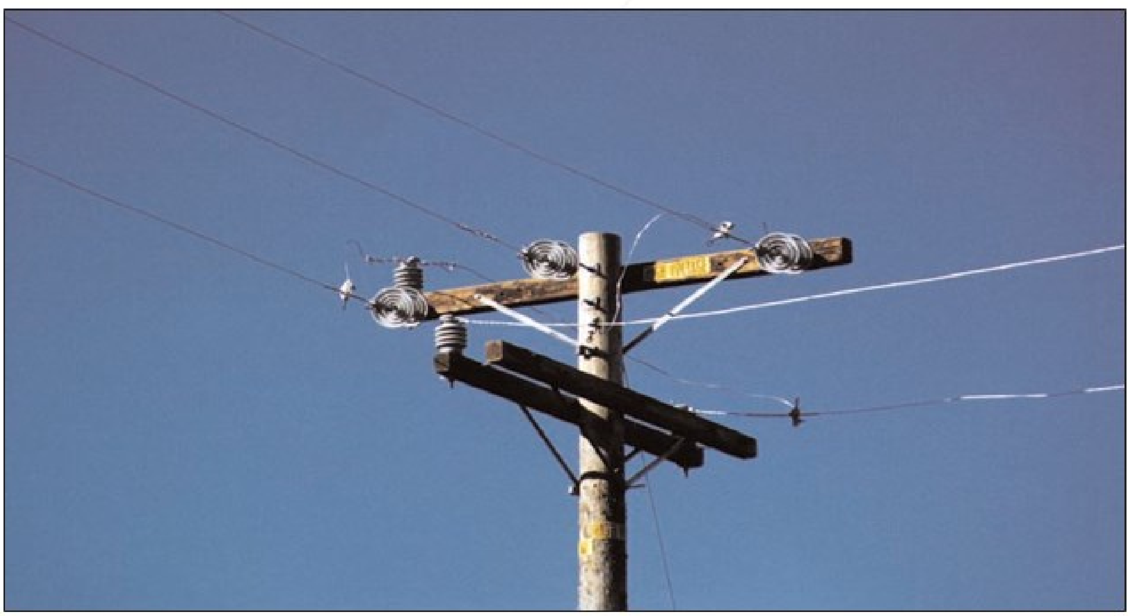


Figure PLC-6: Crossarm Dead-end Corner (Line and Buck)

Distribution Construction

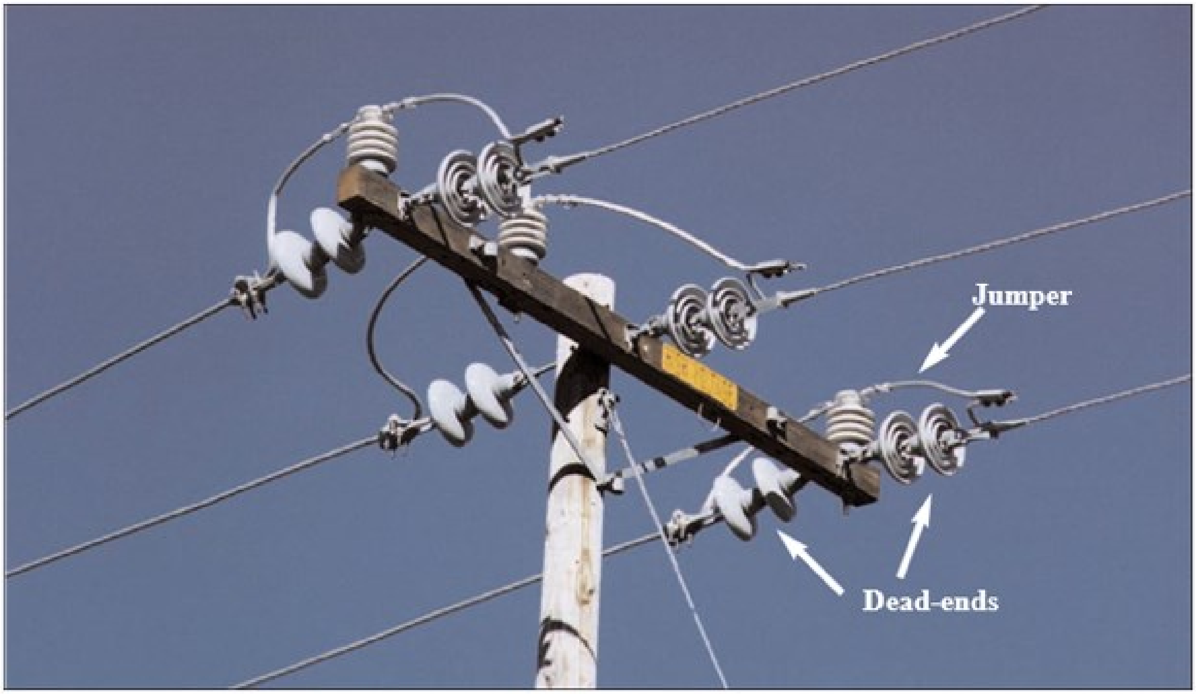


Figure PLC-7: Crossarm Double Dead-end

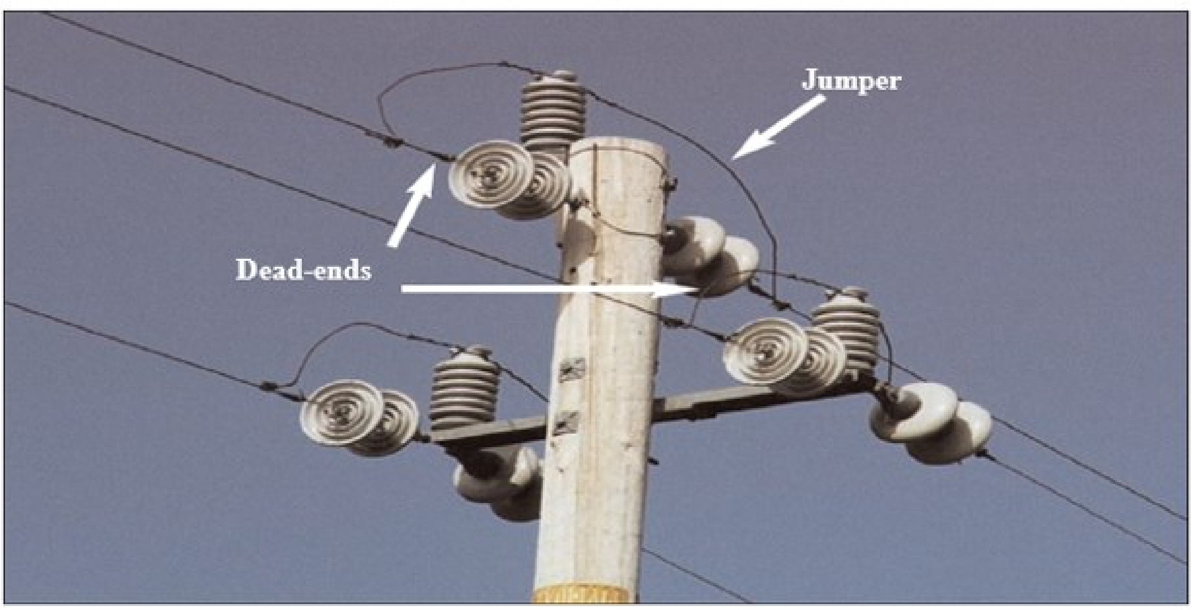


Figure PLC-8: Triangular Double Dead-end

Distribution Construction

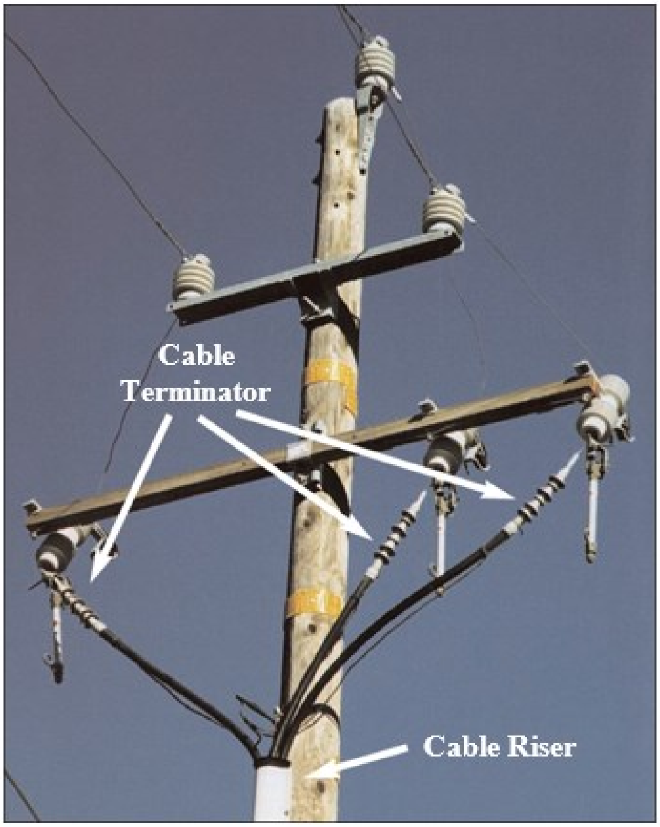


Figure PLC-9: Cable Riser with Cable Terminator

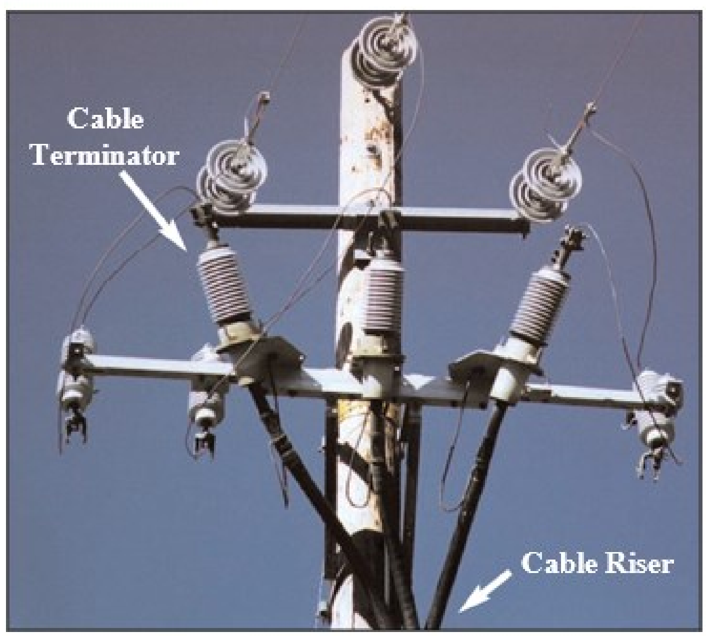


Figure PLC-10: Cable Riser with Cable Terminator

Distribution Construction

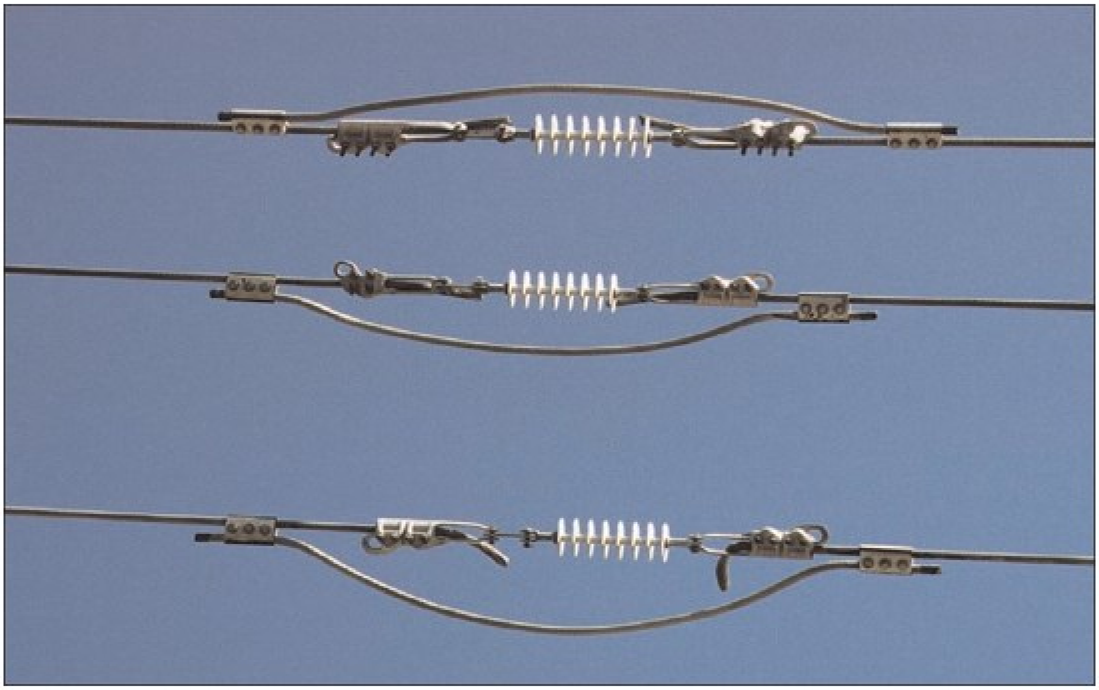


Figure PLC-11: Line Opener

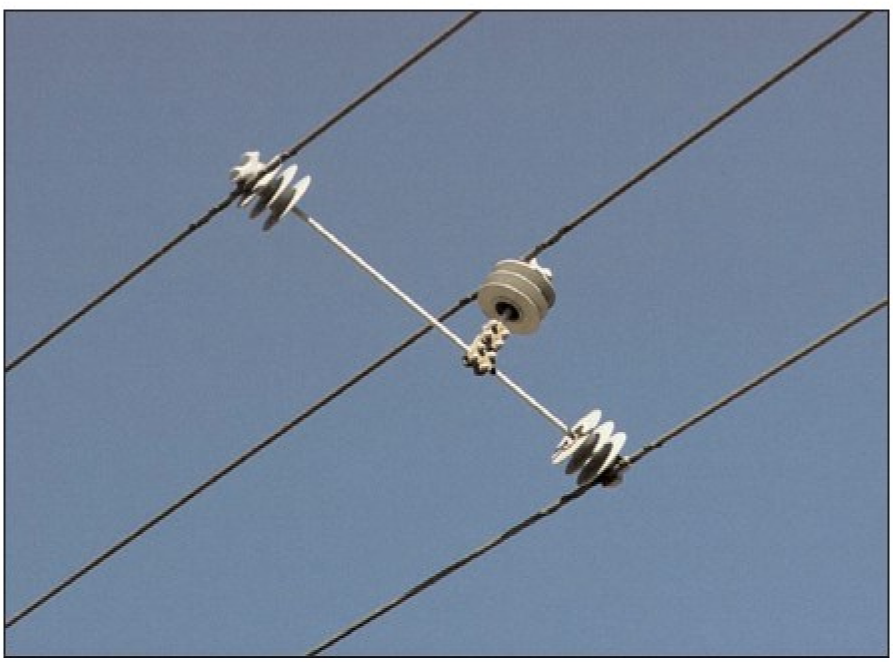


Figure PLC-12: Long Span Conductor Spreader

Distribution Construction

Figure PLC-13: Vibration Damper

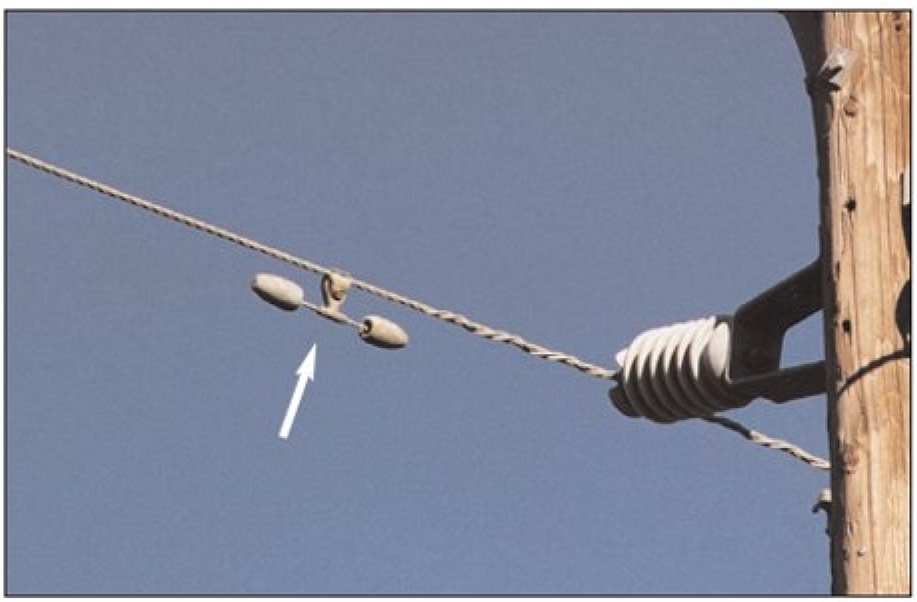


Figure PLC-14: Vibration Damper

Animal and Raptor Protection

Figure PLC-15: Termination with animal protection cover

Figure PLC-16: Cut-out animal protection covers

Animal and Raptor Protection

Figure PLC-17: Insulated Conductor Covering

Figure PLC-18: Raptor Perch

Animal and Raptor Protection

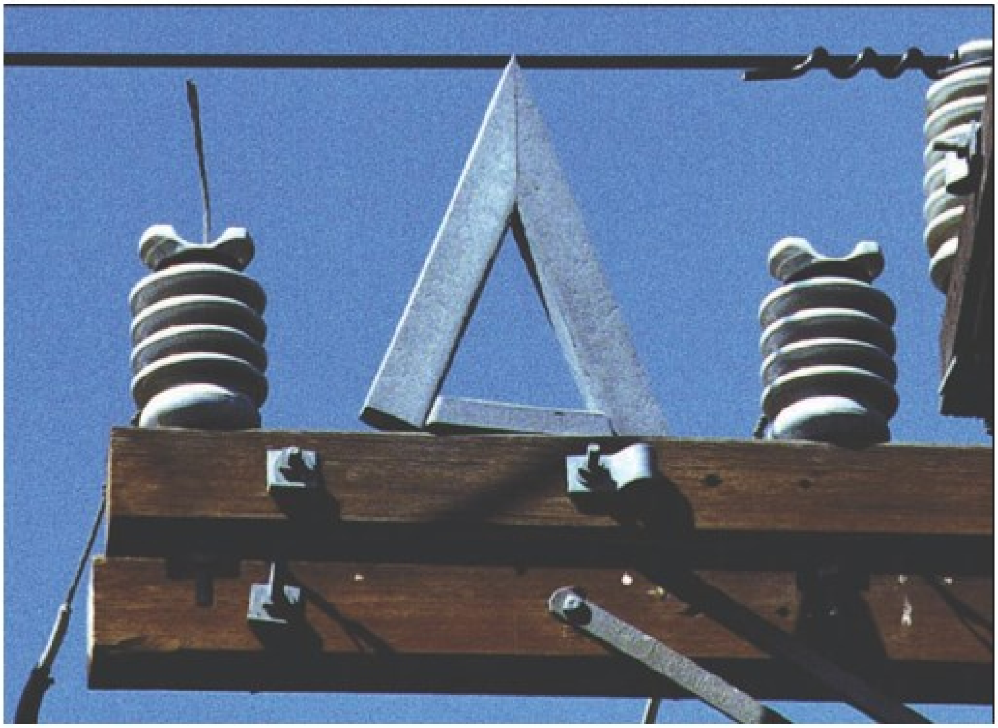


Figure PLC-19: Anti-Perch Guard

Figure PLC-20: Anti-Perch Owl

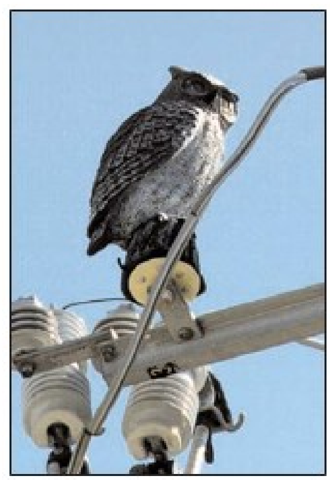


Figure PLC-21: Close-up of Owl on Crossarm

Animal and Raptor Protection

Figure PLC-22: Squirrel Guard

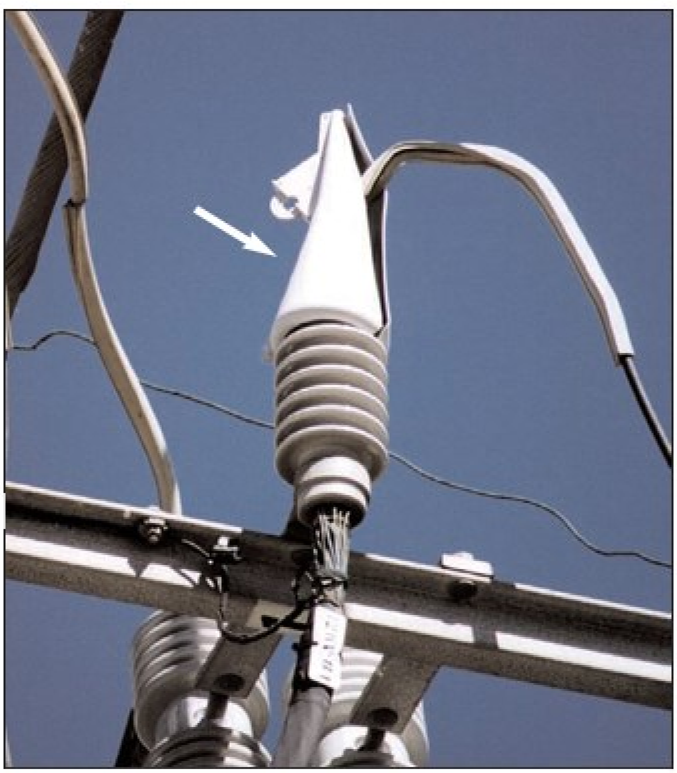


Figure PLC-23: Close up of Squirrel Guard

Animal and Raptor Protection

Figure PLC-24: Raptor Protection Insulator and Wire Cover

Figure PLC-25: Close-up of Insulator and Wire Cover

Figure PLC-26: Bushing Covers

Transmission Construction

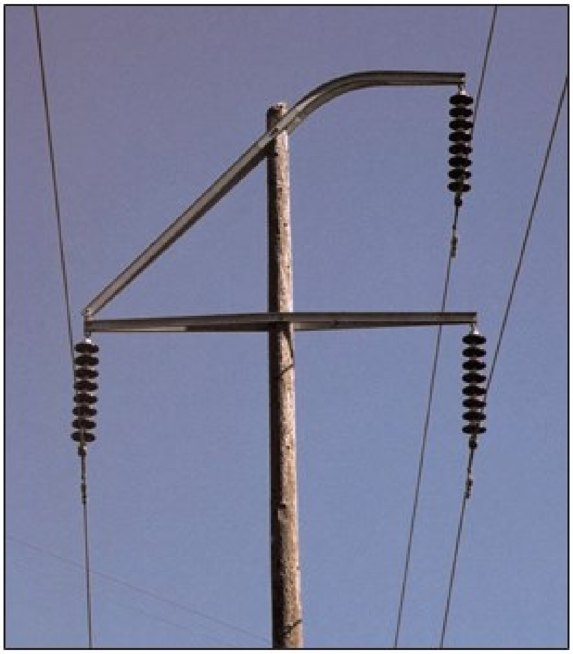


Figure PLC-27: Figure Four (4)

Figure PLC-28: Vertical Post

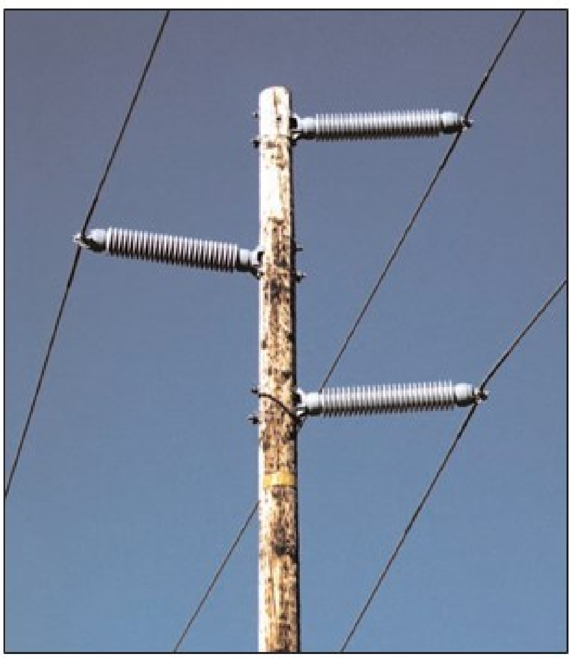


Figure PLC-29: Triangular Post

Transmission Construction

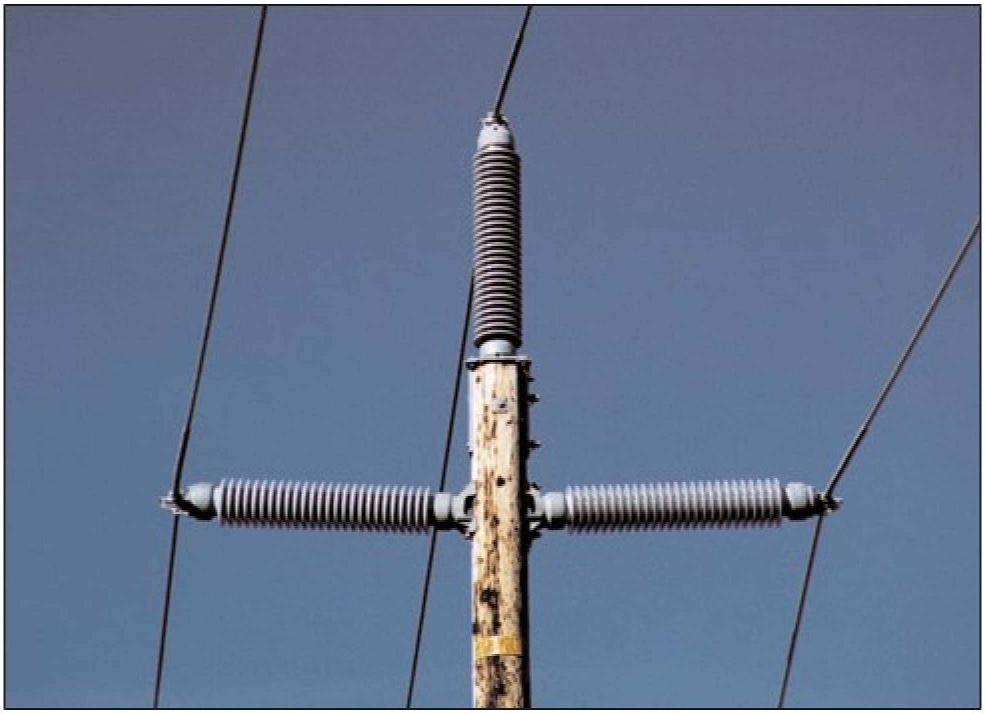


Figure PLC-30: Triangular Configuration

Figure PLC-31: Gull Wing

Transmission Construction

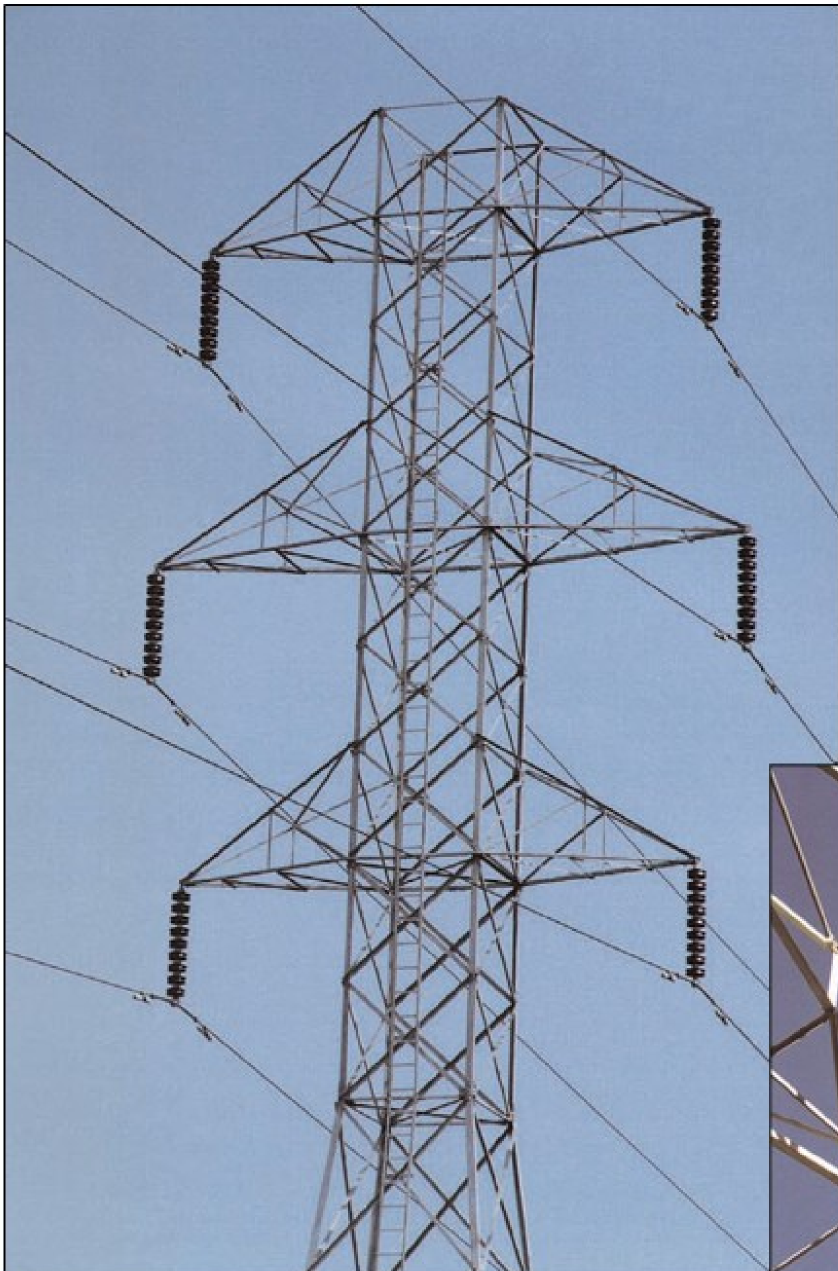


Figure PLC-32: Suspension Tower

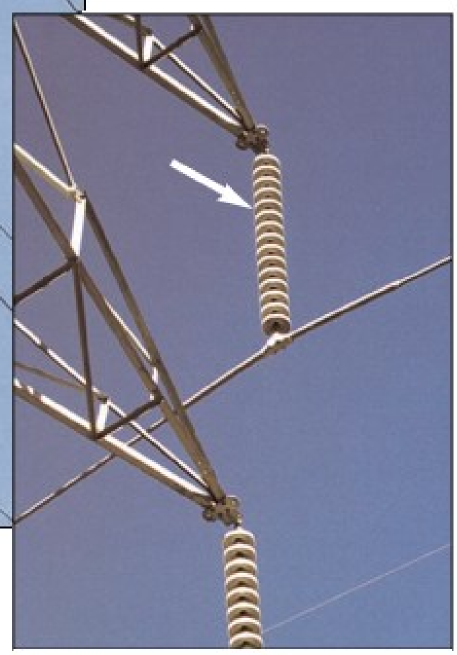


Figure PLC-33: Close-up of Suspension Insulators

Transmission Construction

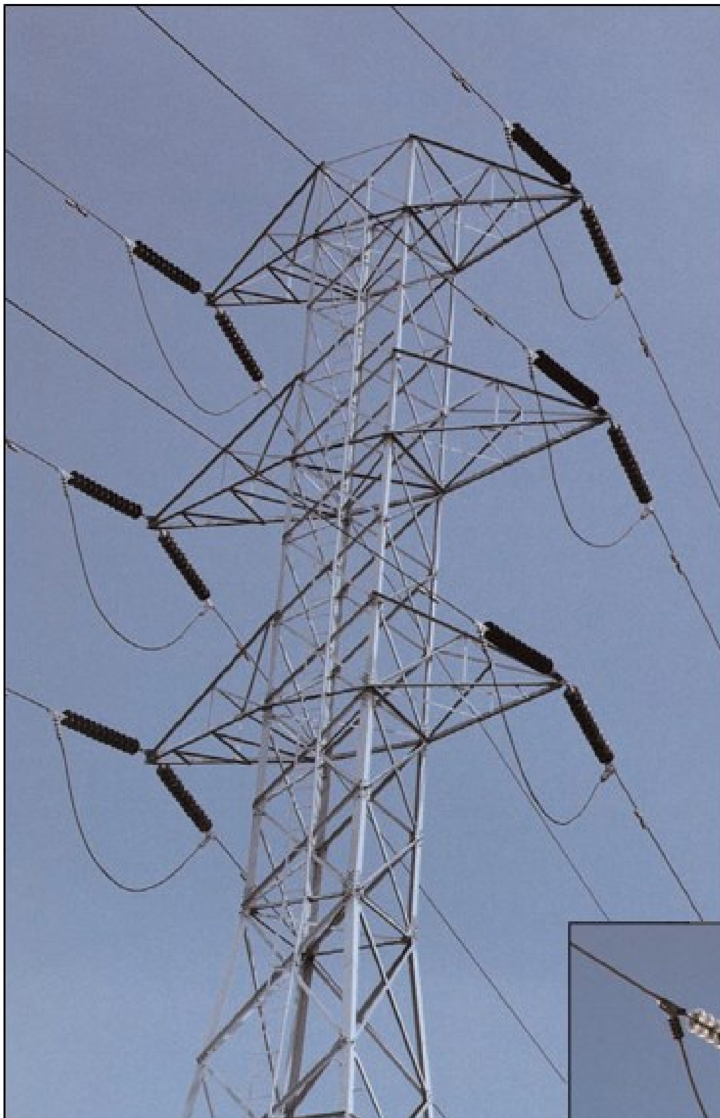


Figure PLC-34: Dead-end Tower

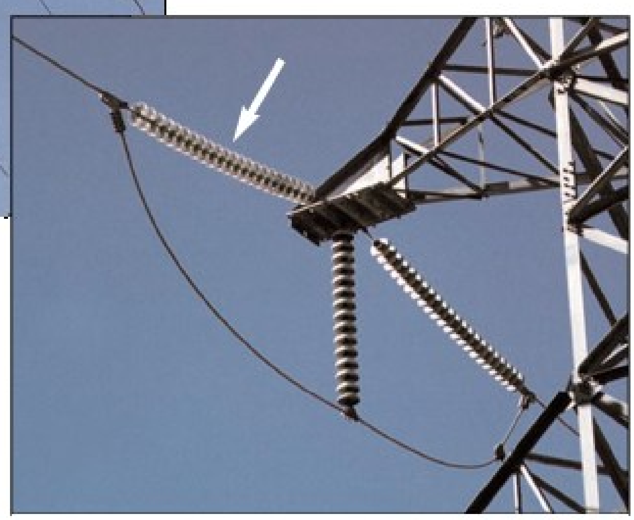


Figure PLC-35: Close up of Dead-end Insulators

Transmission Construction

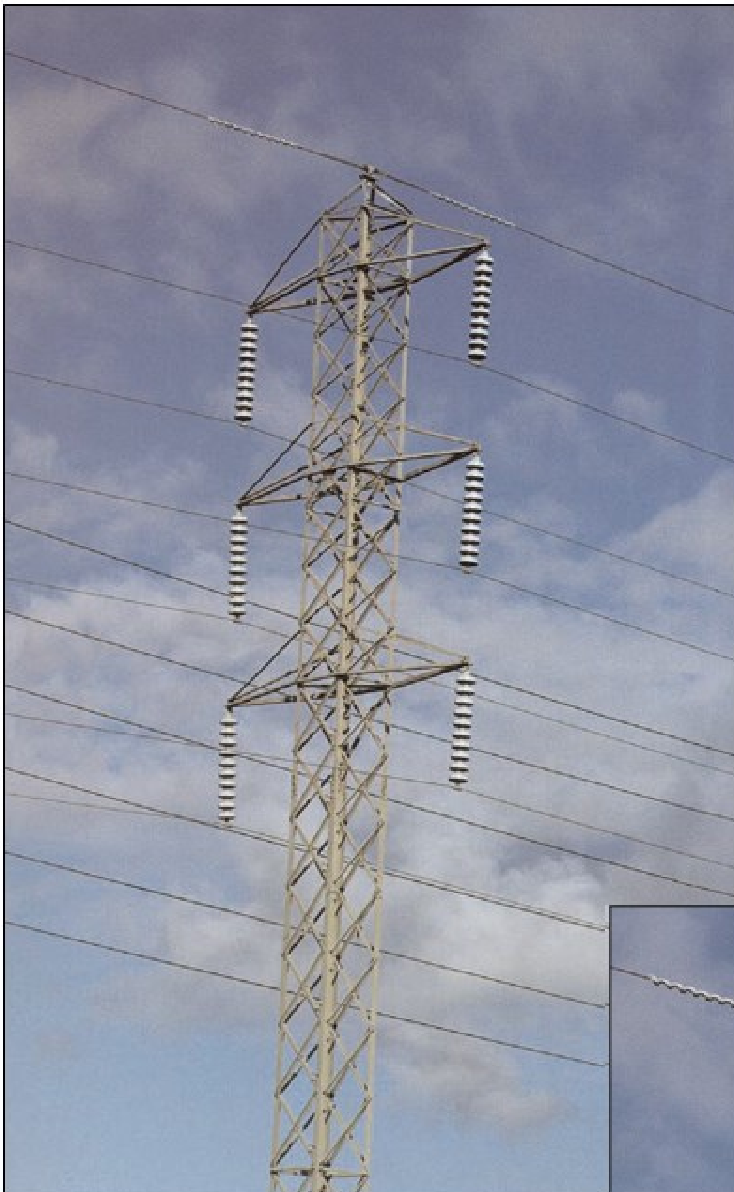


Figure PLC-36 Tangent Transmission Tower with Static Line

Figure PLC-37: Close-up of Static Line

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT G

UTILITY BEST MANAGEMENT PRACTICES

UTILITY BEST MANAGEMENT PRACTICES

TREE RISK ASSESSMENT AND ABATEMENT
FOR FIRE-PRONE STATES AND PROVINCES IN THE
WESTERN REGION OF NORTH AMERICA

UTILITY BEST MANAGEMENT PRACTICES
TREE RISK ASSESSMENT AND ABATEMENT FOR FIRE-PRONE STATES AND PROVINCES IN THE WESTERN REGION OF NORTH AMERICA

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Tree Research & Education Endowment Fund
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UTILITY BEST MANAGEMENT PRACTICES
TREE RISK ASSESSMENT AND ABATEMENT FOR FIRE-PRONE STATES
AND PROVINCES IN THE WESTERN REGION OF NORTH AMERICA

FORWARD

Hazard trees represent a significant liability to the general public, cities, counties, utilities, and State and Federal agencies. If left unmanaged, hazard trees can cause injury to people and property, interruptions to electric service, and threats to the nation's critical infrastructure. In fire-prone states, hazard trees can also fall onto power lines and become the source of damaging wildland fires.

To address the issue the Utility Arborist Association (UAA), through the Tree Research & Education Endowment Fund, has developed the following industry accepted best management practices (BMPs) for assessing tree risk during power line inspections. These BMPs were developed specifically to address hazard tree issues in western region fire-prone states and include the standardization of patrol protocols and inspection practices.

In the future the UAA would like to modify and expand upon these BMPs and have them adopted regionally in North America by utilities. Similar guidelines for tree risk assessment and abatement could also be developed for international use and possibly for broader application outside the utility industry.

UTILITY BEST MANAGEMENT PRACTICES
TREE RISK ASSESSMENT AND ABATEMENT FOR FIRE-PRONE STATES AND PROVINCES IN THE WESTERN REGION OF NORTH AMERICA

INTRODUCTION

Cities, utilities and agencies can be responsible for managing large populations of trees. Often, one of the primary management tasks is to identify, assess and abate hazard trees in order to protect a "target". Techniques for assessing the potential for failure of an individual tree have received considerable attention and the methodologies are widely recognized and implemented. Rather than add another voice to already well-developed practices, the intent of this BMP is to standardize inspection practices for identifying those individual trees within the larger population which should be examined more closely to determine the need for abatement.

These BMPs recognize that implementation of a tree risk assessment and abatement plan will generally vary based on the customary practices of the individual utility, existing inspection schedule, and the laws and regulations that may be applicable in their service area. Additionally, the plan should incorporate knowledge of vegetation types, tree failure patterns and the presence of high-fire risk areas.

Application of these BMPs is intended to be on forested lands and/or heavily wooded areas where it is difficult to thoroughly assess each tree from within the utility easement or right-of-way.

These BMPs were developed recognizing that there are significant challenges when dealing with large numbers of trees. Resources for any entity are always finite, and given a large population of trees and many targets, it is not reasonable to expect close monitoring of all individual trees or abatement of all trees with any defect. Also, as is often the case, the ability of utilities to perform abatement may be restricted due to property owner intervention. Given these constraints, the goal of a utility or other entity is to "manage" rather than "eliminate" the risk.

Please note that many of the terms used in this document are defined in the Glossary of Terms.

BMP DEVELOPMENT PROCESS

At the direction of the UAA, a Hazard Tree Identification Protocol working group was assembled. The group included representation from various stakeholder groups. The working group convened two workshops and communicated regularly during the development of these BMPs. Sub-committees were established to address various issues that were identified during the workshops and in subsequent communications. A review committee was also established to evaluate and provide input on these BMPs.

UTILITY BEST MANAGEMENT PRACTICES
TREE RISK ASSESSMENT AND ABATEMENT FOR FIRE-PRONE STATES AND PROVINCES IN THE WESTERN REGION OF NORTH AMERICA

TABLE OF CONTENTS

UTILITY BEST MANAGEMENT PRACTICES
TREE RISK ASSESSMENT AND ABATEMENT FOR FIRE-PRONE STATES AND PROVINCES IN THE WESTERN REGION OF NORTH AMERICA

1. PATROLS, INSPECTIONS, AND METHODS USED TO ASSESS TREE RISK

Typically, each utility develops a maintenance plan that includes methods for patrolling and inspecting its electric facilities. This can include patrolling from the ground, on foot or in a vehicle, or by using aircraft, whether fixed wing or helicopter, or by the use of Light Detection and Ranging (LIDAR), in combination with other methods, to determine tree health. These methods can vary significantly between utilities as can the methods for assessing tree risk. This BMP suggests the following:

1.1 PATROL AND INSPECTION METHODS

Patrol and inspection methods used to assess tree risk are utility and site specific. Each utility should have a plan in place that describes the methods used based on site specific requirements.

For the purpose of this BMP, the geographic area assessed during a patrol includes all areas that contain trees tall enough to strike an Overhead High-voltage Conductor. This area would be considered the “strike zone”.

The following sections of this BMP define how patrols and inspections should be carried out to identify tree risk.

1.2 LINE PATROL

A Line Patrol is a periodic, ground-based visual assessment of trees, which can be observed from within or closely adjacent to an easement or right-of-way, in order to identify tree defects that could cause a tree, or parts of a tree, to fall directly into an Overhead High-voltage Conductor.

1.2.1 Each utility should define and establish specific guidelines, including frequency and methodology, for performing a Line Patrol.

1.2.2 A Line Patrol is intended to support Line Clearing Operations which are defined as: Tree pruning and removal, performed on a regular basis that supports electric service reliability, public safety, and compliance with laws and regulations related to utility vegetation management.

1.2.3 A Detailed Tree Inspection may occur when evidence warranting the detailed inspection is observed during a Line Patrol.

1.2.4 This BMP recognizes that a Line Patrol does not necessarily entail a detailed inspection of each tree within the strike zone.

1.3 DETAILED LINE PATROL

A Detailed Line Patrol is a periodic, ground-based visual assessment of trees within the strike zone, in order to identify tree defects that could cause a tree, or parts of a tree, to fall directly into an Overhead High-voltage Conductor.

1.3.1 Each utility should define and establish specific guidelines, including frequency and methodology, for performing a Detailed Line Patrol.

1.3.2 A Detailed Tree Inspection may occur when evidence warranting the detailed inspection is observed during a Detailed Line Patrol.

1.3.3 This BMP recognizes that a Detailed Line Patrol does not necessarily entail a detailed inspection of each tree within the strike zone

1.4 DETAILED TREE INSPECTION

Close proximity, 360 degree visual inspection of an individual tree from the ground.

1.4.1 The inspector determines the presence, significance, and severity of a tree defect if one exists.

1.4.2 The inspector considers the severity of the defect when prescribing abatement action.

2. FREQUENCY OF PATROLS

Patrol frequency varies among utilities based on individual needs, applicable laws and regulation, species, vegetation type, line voltage, and the presence of high fire risk areas.

Overhead High-voltage Conductors are electric lines that are energized at more than 750 Volts. Voltages for distribution and transmission lines typically range from 2.4kV to 765kV.

Overhead Low-voltage Conductors are electric lines that are energized at 750 Volts or less. For the purpose of this BMP, an Overhead Low-voltage Conductor refers to a line that is strung pole to pole and that is not associated with Overhead High-voltage Conductors (no Overhead High-voltage Conductors in the same span).

The following provides a recommended framework for developing patrol frequencies for Overhead High-voltage and Low-voltage Conductors.

2.1 OVERHEAD HIGH-VOLTAGE CONDUCTORS

A multi-component approach should be employed when determining the frequency of patrols for Overhead High-voltage Conductors. Each utility should determine their Line Patrol frequency and establish a separate Detailed Line Patrol schedule. For example, a Line Patrol could occur on an annual basis and a Detailed Line Patrol could occur every 3-5 years or as determined by the Line Patrol.

2.1.1 This practice should be viewed as a single approach involving two separate components

2.2 OVERHEAD LOW-VOLTAGE CONDUCTORS

Each utility should define a patrol and abatement strategy for Overhead Low-voltage Conductors (pole to pole, not pole to weatherhead), dependent on fire risk and regulatory requirements.

2.2.1 Overhead Low-voltage Conductors that are strung pole to pole are also known as Secondary Conductors.

3. ASSESSING TREE RISK

3.1 TREE DEFECTS

The ability to assess tree risk and tree failure potential is a baseline requirement for any utility vegetation management program. Inspectors must have the ability to identify the likelihood of a tree's failure and be able to determine the appropriate abatement action.

Appendix 'A' contains a list of some tree-specific defects that may trigger a Detailed Tree Inspection or appropriate abatement action.

Although all of the tree-specific defects listed in Appendix 'A' are considered potential triggers for a Detailed Tree Inspection, these defects may not be considered as causing a risk to the Overhead High-voltage Conductors after a Detailed Tree Inspection has been conducted.

3.2 SITES THAT REQUIRE ADDITIONAL CONSIDERATION

It may also be necessary to look at some sites in more detail due to environmental conditions, past management practices, or other human activity.

Appendix 'B' contains a list of site-specific conditions that should be considered while conducting a patrol.

3.3 TREE RISK ASSESSMENT PROCEDURE

3.3.1 The inspector determines the presence, severity, and significance of a tree defect if one exists.

3.3.2 The inspector considers the severity of the defect when prescribing an abatement action and prioritizes the work accordingly.

3.3.3 Some utilities may require that an inspector's recommendation be reviewed by a supervisor or appropriate utility personnel.

3.3.4 The tree care contractor or utility personnel, when in the field, may make a follow-up determination of the recommended abatement action.

3.3.5 It should be recognized that some recommendations for abatement treatments may be limited by legal constraints or by the property owner.

4. ASSESSMENT AND ABATEMENT PLAN

Trees that have been determined to be an unacceptable risk to high-voltage conductors during an assessment generally require some form of abatement action, whether pruning or removal. A plan for assessment and abatement should be developed based on the varying conditions that can be encountered in the field.

4.1 Each utility should have a plan and procedure in place for the assessment and abatement of hazard trees. The assessment and abatement plan should address regulatory requirements, patrol schedule, severity of tree conditions, resource availability, environmental impacts, property owner and land manager concerns.

4.2 The plan should specify the party or parties responsible for prescribing and executing the abatement.

5. WORKER QUALIFICATIONS

Workers that perform tree risk assessment patrols and inspections should receive adequate training, as defined by the utility, to satisfactorily perform the tasks needed to identify hazard trees and recommend abatement procedures. At a minimum all workers performing tree risk assessments should be able to recognize all tree-specific defects listed in Appendix 'A' and the site conditions listed in Appendix 'B', and understand what those conditions imply regarding abatement.

5.1 Each utility should require that all personnel performing tree risk assessment patrols and inspections receive training specific to tree risk assessment. It should be required that all tree risk assessment training be recorded and updated by the individual's employer.

5.2 Each utility should define minimum qualifications necessary to perform tree risk assessment patrols and inspections. Minimum qualification requirements should take into consideration the individual's knowledge of utility assets, arboriculture-related education and experience, industry certifications and in-house training.

5.2.1 A list of recommended training resources is included as Appendix 'C'.

6. DOCUMENTATION

Documentation and data collection related to vegetation management can vary significantly among utilities. The process used to document hazard trees may include tagging, collecting GPS information, or the use of other means to document and track hazard trees such as in an inventory system.

6.1 Each utility should have documentation procedures and data collection requirements for vegetation management. The utility's existing requirements should be incorporated into their tree risk assessment and abatement plan.

GLOSSARY OF TERMS

Detailed Line Patrol:
Periodic, ground-based visual assessment of trees within the strike zone, in order to identify tree defects that could cause a tree, or parts of a tree, to fall directly into an Overhead High-voltage Conductor.

Detailed Tree Inspection:
Close proximity, 360 degree visual inspection of an individual tree from the ground.

Line:
Conductors, structures and related equipment located in an easement or right-of-way for the purpose of transmitting electricity.

Line Clearing Operations:
Tree pruning and removal, performed on a regular basis that supports compliance with laws and regulations related to utility vegetation management.

Line Patrol:
Periodic, ground-based visual assessment of trees, which can be observed from within or closely adjacent to an easement or right-of-way, in order to identify tree defects that could cause a tree, or parts of a tree, to fall directly into an Overhead High-voltage Conductor.

Overhead High-voltage Conductor:
Electric lines energized at more than 750 Volts. Voltages for distribution and transmission lines typically range from 2.4kV to 765kV.

Overhead Low-voltage Conductor:
Electric lines energized at 750 Volts or less. For the purpose of this BMP, an Overhead Low-voltage Conductor refers to a line that is strung pole to pole and that is not associated with Overhead High-voltage Conductors (no Overhead High-voltage Conductors in the same span).

Secondary Conductor:
An open wire or bundled low-voltage line that is typically strung from pole to pole.

Strike Zone:
The area within, and adjacent to the easement or right-of-way from which a tree can directly strike an Overhead High-voltage Conductor.

APPENDIX 'A'

TREE-SPECIFIC DEFECTS OR POTENTIAL TRIGGERS FOR THE DETAILED INSPECTION OF TREES WITHIN THE STRIKE ZONE (Note: This list is not intended to be all inclusive or address the severity of a defect.)

Basal wound
Bleeding and/or resinosus
Bulges and/or swellings
Cankers, including bleeding & gall rust
Cavities
Codominant or multiple stems from base or higher on trunk
Conks indicating heart rot, root rot, sap rot or canker rot
Cracks including shear
Dead branches and/or top
Dieback of twigs and/or branches
Embedded wires or cables
Excessive lean or bow
Fire damage
Foliage – off-color, flagging or loss
Hazard beam
History of limb failure(s) on tree
Included bark
Insect activity such as frass from termites, bark beetles or carpenter ants
Large branches overhanging power line
Lightning damage
Live crown ratio below 30%
Mistletoe – dwarf or broad-leaf
Nesting holes – birds, mammals, insects
Past poor pruning practices
Roots injured, exposed, undermined or uplifted
Seam
Species failure patterns
Unnatural or structurally unsound canopy weight distribution
Weak, unsound branch attachments

APPENDIX 'B'

SITE-SPECIFIC CONDITIONS OR POTENTIAL TRIGGERS FOR SITES THAT CONTAIN TREES WITHIN THE STRIKE ZONE

Areas known to be affected by introduced tree pathogens
Areas of recent clearing/new edge
Change in drainage
Change in grade
Construction – including trenching, paving or road construction
Cultural disturbance to landscape - natural or unnatural
Diseased center – dead tree in middle and dying trees around it
High stand density with single species composition
History of failure(s) at site
History of repeated outages on circuit
Fire damage
Raptor nests above lines
Recent thinning or logging
Soils prone to slides
Specific conditions like high winds
Storm damage
Wet sites

TRAINING RESOURCES

Reference	Author (s)	Source	Publisher
A Field Guide to Insects & Diseases of California Oaks	Tedmund J. Swiecki & Elizabeth A. Bernhardt	United States Department of Agriculture - Forest Service - General Technical Report PSW-GTR-197	United States Department of Agriculture - Forest Service
A Handbook of Hazard Tree Evaluation for Utility Arborist	James R. Clark & Nelda Matheny	International Society of Arboriculture (ISA)	International Society of Arboriculture (ISA)
A New Tree Biology	Dr. Alex L. Shigo	Shigo & Trees, Associates	Shigo & Trees, Associates
A Photographic Guide to the Evaluation of Hazard Trees in Urban Areas	James R. Clark & Nelda Matheny	International Society of Arboriculture (ISA)	International Society of Arboriculture (ISA)
ANSI A300 – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices (Pruning)	Various contributors	American National Standards Institute	American National Standards Institute
ANSI Z133 – Pruning, Trimming, Repairing, Maintaining, and Removing Trees, and Cutting Brush – Safety Requirements	Various contributors	American National Standards Institute	American National Standards Institute
California Tree Failure Report Program	Laurence R. Costello, Bruce Hagen & Katherine S,.Jones	University of California	University of California
Diseases & Insect Pests of Northern & Central Rock Mountain Conifers	Susan Hagle, Kenneth Gibson & Scott Tunnock	United States Department of Agriculture-Forest Service Publication # R1-03-08	United States Department of Agriculture - Forest Service
Diseases of Pacific Coast Conifers	Robert F. Scharpf	United States Department of Agriculture - Forest Service - Handbook 521	United States Department of Agriculture - Forest Service
Evaluating Tree Defects, 2nd Edition	Ed Hayes	Safetrees	Safetrees
Field Guide for Danger Tree Identification & Response	Richard Toupin & Michael Barger	United States Department of Agriculture-Forest Service Publication # R6-NR-FP-PR-03-05	United States Department of Agriculture - Forest Service

APPENDIX 'C'

Hazard Trees - Recognizing them before you climb	Manfred Mielke, Plant Pathologist, NA FHP	United States Department of Agriculture - Forest Service	United States Department of Agriculture - Forest Service
International Tree Failure Database	NA	http://svinetfc2.fs.fed.us/natfdb/	NA
Manual of Pacific Coast Trees	McMinn & Maino	University of California Press Berkeley.	University of California Press Berkeley.
Modern Arboriculture	Dr. Alex L. Shigo	Shigo & Trees, Associates	Shigo & Trees, Associates
Pests of the Native California Conifers	UCPress, 2003, Wood et al	University of California	University of California
Power Line Fire Prevention Field Guide	Dan Nichols, Robert Loggins & R.C. "Bob" Fraitag	California Department of Forestry & Fire Protection	California Department of Forestry & Fire Protection
Pruning Trees Near Electric Utility Lines	Dr. Alex L. Shigo	Shigo & Trees, Associates	Shigo & Trees, Associates
Recognizing Tree Hazards - A Photographic Guide for Homeowners	Laurence R. Costello, Bruce Hagen & Katherine S,.Jones	University Of California Agriculture & Natural Resources Communication Services - Publications - Publication # 21584	University Of California Agriculture & Natural Resources
Roadside Vegetation Management: Protocol for Prioritizing Surveys & Recognizing, Rating, Documenting & Treating Hazard Trees along Forested Roadways in Northeastern Oregon	Craig L. Schmitt	United States Department of Agriculture - Forest Service Technical Report BMPMSC-04-01	United States Department of Agriculture - Forest Service
Ten Common Wood Decay Fungi on California Trees	Gary W. Hickman & Ed Perry	University of California - Cooperative Extension	Western Chapter-International Society of Arboriculture (ISA)
Tree Hazards-Recognition & Reduction in Recreational Sites	David w. Johnson	United States Department of Agriculture - Forest Service Technical Report R2-1	United States Department of Agriculture - Forest Service
Urban Tree Risk Management	Jana Albers, Jill Pokorny & Dr, Gary Johnson	United States Department of Agriculture-Forest Service Publication # NA-TP-03-03	United States Department of Agriculture - Forest Service

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT H

UTILITY PROCEDURE: TD-7102P-01 VEGETATION MANAGEMENT DISTRIBUTION INSPECTION PROCEDURE

Vegetation Management Distribution Inspection Procedure

SUMMARY

This procedure outlines the tasks necessary to fulfill the inspection requirements of the Distribution Vegetation Management program. The inspection of vegetation around Pacific Gas & Electric Company's (PG&E) overhead electric distribution lines and facilities is performed to maintain safe and reliable operation.

Level of Use: Informational Use

TARGET AUDIENCE

Distribution Vegetation Management Inspectors (VMI)

Supervising Vegetation Management Inspector

Vegetation Program Manager (VPM)

SAFETY

NA

BEFORE YOU START

All individuals must complete PG&E Academy training required for inspections prior to performing this procedure. Training expectations are available at Training Expectations.

TABLE OF CONTENTS

PROCEDURE STEPS

1 Before Going Out into the Field

1.1 Before going out into the field, the VMI must PERFORM the following steps:

1. CONFIRM with the supervisor which system of record will be used to record tree information, OneVM or VMD.

2. CONFIRM access to the appropriate system of record.

3. GATHER and review the following information:

   - Current inspection maps (including EVM historical work)
   - Work packets
   - Pre-Patrol Report
   - Historical outage data
   - Issues that may occur on the assigned circuit, as provided by their direct supervisor.

2 Requirements While in the Field

2.1 Unusual and Unsafe Conditions

1. IF a third party is threatening the VMI's physical safety,

   THEN the VMI must PERFORM the following steps:

   a. GET TO A SAFE AREA

   b. CALL 9-1-1 or local emergency services and/or NOTIFY the supervisor or appropriate leadership.

2. At any time during the visit to a location, the VMI must REPORT any of the following:

   - Any unsafe site situations (i.e., site conditions preventing access or inspection).
   - Abnormal field conditions (whether owned by PG&E or a third party), per TD-7102P-09, "Reporting Abnormal Field Conditions Procedure."

3. IF any of the vegetation affects distribution facilities such that it requires Priority 1 or Priority 2 mitigation,

   THEN the VMI must refer to Utility Procedure TD-7102P-17, "Vegetation Management Priority Tag Procedure".

Vegetation Management Distribution Inspection Procedure

2.1 (continued)

4. IF any of the vegetation affects transmission facilities such that it requires Hazard

5. Notification-Immediate or Hazard Notification-Urgent designation,

   THEN REFER to Utility Procedure TD-7103P-09, "Transmission Vegetation Management Hazard Notification Procedure."

2.2 Refusals

1. IF at any time during inspection of a location a customer, property owner, or agency obstructs or delays PG&E pre-inspection work,

   THEN the VMI must FOLLOW the steps in the document titled TD-7102P-04, "Distribution Vegetation Refusal Procedure."

2.3 Palm Trees

1. IF at any time during the visit to a location the VMI encounters a palm tree that may encroach the MDR,

   THEN the VMI must FOLLOW the steps in Attachment 1, "Strategies to Manage and Reduce Palms."

2.4 Environmental Considerations

1. If the VMI encounters conditions that may require Environmental review (bird's nest, riparian area, VELB habitat, etc.),

   THEN DOCUMENT the conditions in the system of record.

3 Performing an Inspection

3.1 What to Inspect

1. The VMI must INSPECT the following:

   - Vegetation that has or may encroach the MDR, based on anticipated growth rates before the next annual work cycle (see Appendix A, Minimum Distance Requirements [MDR]) and considering normal weather patterns for the local area or line position or line conditions.
   - Vegetation (categorized as either a whole tree or portion of tree) that may fall into or otherwise impact PG&E electric facilities.
   - Any vegetation that is causing significant strain or abrasion to the secondary conductors (excluding service drops).
   - All Idle lines as if they are energized.
   - Distribution underbuilt for vegetation that could fall into transmission structures, guys, or poles, regardless of right-of-way (ROW) or easement width.
   - Areas outside fenced areas, including portions of distribution line span crossing substation fence at substations, generation stations, or switchyards in the inspection area.
   - Enhanced Vegetation Management (EVM) segments that have been claimed and reported as part of the EVM WMP commitments (refer to Attachment 2, "EVM Commitments").

3.2 Handling Inspections that Cannot be Completed

1. If an inspection cannot be completed because of constraints or external factors, the VMI must RECORD the type of constraint or external factors involved in the system of record.

3.3 Inspecting Vegetation

1. The VMI must GO TO their first location and PERFORM a Level 1 visual inspection of the vegetation surrounding the facilities, looking for the following:

   - On overhead electric distribution primary and secondary conductors and facilities (excluding service drops), IDENTIFY:
     - Vegetation that will encroach the MDR (see Appendix A, Minimum Distance Requirements (MDR)) before the next annual work cycle.
     - Any vegetation that has already encroached the MDR.

3.3 (continued)

- For trees that may fall into or may contact the line:
  - Dead trees or portions of trees that are rotten or weakened by decay or disease
  - Rotten or diseased portions of otherwise healthy trees that overhang or lean (due to outside influences: soil structure, soil heaving, weather conditions, cracking, breaking, etc.) toward the line (refer to Appendix E, "Information About Tree Lean").
- Any distribution underbuilt spans for any of the above conditions.
  - The VMI must INSPECT the distribution underbuilt spans as described in the document titled TD-7103P-01, "Transmission Routine (Non-Orchard) Patrol Procedure (TRPP)."
    - IF the VMI DISCOVERS vegetation or abnormal conditions that adversely affect transmission primary and/or secondary facilities,
    - THEN the VMI must APPROPRIATELY REPORT them.
- IF a tree or limb is more than 6 in. in diameter at line height,

  AND is more than 10 in. DBH,

  AND within 6 - 48 in. of a conductor (in HFTD/SRA) or 6 - 18 in. of a conductor (in LRA),

  THEN PERFORM the steps in Attachment 3, "Identifying Major Woody Stems" to identify and record the potentially exempt major woody stem.

2. IF (while performing the Level 1 inspection) the VMI identifies a tree or trees with conditions found in the Hazard Trees/Vegetation Clearance section of the "California Power Line Fire Prevention Field Guide" (see Appendix B, Overview of Tree Defects and Site Conditions),

   OR, if the VMI suspects a tree may have one or more of those conditions,

   THEN PERFORM a Level 2 assessment of that tree.

3. IF work is not necessary to maintain safety and compliance as defined above,

   THEN INSPECT the next tree on the assigned circuit.

4. IF work is necessary, PROCEED to section 4, "Prescribing Work."

4 Prescribing Work

NOTE
G.O. 95, Rule 35, Appendix E, recommends minimum 12-feet of clearance at time of trim in High Fire Threat District (HFTD). PG&E extends this minimum clearance to tree work within HFRA. Idle lines must be treated as energized and work prescribed accordingly.

4.1 Using the information gathered in Section 3 and their professional judgement, the VMI must DETERMINE which of the two options in this section applies to the vegetation,

AND PRESCRIBE the work in that option in the system of record.

1. Prescribing Non-EVM Work

   a. IF a tree shows any of the following characteristics:

      - Has the potential to encroach within minimum distances required to maintain compliance with G.O. 95, Rule 35, or PRC 4293 (see Appendix A, Minimum Distance Requirements (MDRs),

      - Shows evidence of creating strain or abrasion on secondary lines,

        OR may fall into or otherwise impact secondary conductors.

      - Is dead or has portions of it that are dead are rotten or weakened by decay or disease,

        AND overhangs or leans toward and may fall into or may contact the line from the side.

      - Is healthy but has one or more portions that are rotten or diseased,

        AND overhangs or leans toward and may fall into or may contact the line from the side.

      THEN the VMI must PERFORM the following steps:

      (1) Prescribe removal.

         - IF prescribing removal of a tree that may resprout,

           OR IF a stump is currently resprouting,

           THEN refer to Attachment 4, “Handling Stump Resprouts.”

4.1 (continued)

(2) If removal is not practical,

THEN prescribe pruning such that the tree will maintain compliance for three annual work cycles.

(3) If pruning to maintain compliance for three annual work cycles is not an option,

THEN prescribe pruning such that the tree will maintain compliance for one annual work cycle.

(4) If pruning to maintain compliance for one annual work cycle is not an option,

THEN prescribe Bi-Annual clearance.

- The VPM must CONSIDER the mitigation options outlined in Attachment 5, "Bi-Annual Considerations" and DETERMINE a course of action for the tree.

(5) IF the customer refuses removal and/or any pruning, THEN the VMI must FOLLOW the steps in Utility Procedure TD-7102P-04, "Distribution Vegetation Refusal Procedure,"

AND ESCALATE to the VPM.

2. Prescribing Work to Maintain EVM Clearances

a. Prescribe work to maintain the following EVM clearances for the entire segment:

- A clear vertical plane (clear to sky) of a minimum of 4 ft. from the outside conductor.

- EVM-required radial clearances of a minimum of 12 ft. at time of trim.

4.2 After prescribing tree work (or recording a refusal), the VMI must PROCEED to section 5, "Marking a Tree."

5 Marking a Tree

5.1 The VMI must MARK the tree, using at least one of the methods in this section once tree work has been identified.

1. Painting

> **NOTE**
>
> Paint colors are assigned to programs and to specific years of some programs. See Appendix D, "Tree Marking Colors."

a. Spray the paint near the base of a tree using one of the following shapes:

- A dot for pruning.
- An X for removal

b. When painting a mark, use the following guidelines:

- The best location for marking is above surrounding vegetation (grass and bushes) and above any expected snowline.
- The best location for marking is on the side that a tree crew will likely see first.
- Spray new marks over any marks from previous years, but with some of the older mark still showing.
- Cover incorrect marks with black or brown paint.

2. Flagging

> **NOTE**
>
> Flag colors are assigned to programs and to specific years of some programs. See Appendix D, "Tree Marking Colors."

a. SECURELY ATTACH flagging that will help the tree crew identify the tree.

3. Cannot Paint or Flag

a. IF the VMI cannot paint or flag a tree,

THEN UPDATE the tree record with the code CNP (cannot paint) or CNF (cannot flag) and a description of the tree's location within the span.

5.2 After marking the tree, the VMI must PROCEED to section 6, "Notifying the Customer/Property Owner of Upcoming Work."

6 Notifying the Customer/Property Owner of Upcoming Work

6.1 Agency Land Notification

1. IF work is prescribed on agency land,

   THEN invoke the ERTC process in coordination with Environmental Support.

6.2 Customer/Property Owner Notification

1. The VMI must PERFORM the following steps:

   a. ATTEMPT to contact the customer/property owner directly and DESCRIBE the work to be performed.

      - Acceptable methods of contact include:
        - Direct contact in person
        - Phone Calls
        - Email
        - Door hanger
        - Letters

   b. IF the customer/property owner does not respond to the first contact attempt,

      THEN ATTEMPT TO CONTACT the customer/property owner at least two more times (for total of three times).

   c. If the customer/property owner does not acknowledge the receipt of the information,

      THEN ENTER the details and method of the notification attempts into the system of record.

6.3 Customer/Property Owner Refusal

1. IF the customer/property owner refuses to allow the work to proceed,

   THEN the VMI must FOLLOW the steps in the document titled TD-7102P-04, "Distribution Vegetation Refusal Procedure."

6.4 After performing the above steps, the VMI must inspect the next location on their assigned circuit.

END of Instructions

DEFINITIONS

Abnormal Field Condition: Field conditions that may include, but are not limited to, broken cross arms, floaters, objects on wires, broken poles, frayed conductors, arcing wires, etc.

Abrasion: Damage to insulation resulting from friction between vegetation and conductors. Scuffing or polishing of the insulation or covering is not considered abrasion

Basic Assessment (Level 2): A detailed visual inspection of a tree and surrounding site that may include the use of simple tools. It requires that a tree risk assessor inspect completely around the tree trunk looking at the visible aboveground roots, trunk, branches, and site.

Level 2 inspections are ground-based.

Constraint: A situation that occurs when a customer, property owner, or agency obstructs or delays PG&E pre-inspection work or the completion of the intended tree work.

Distribution Underbuilt: The presence of electric distribution lines located directly under and parallel with the transmission lines and attached to the same pole or structure.

External Factors: Events and conditions that are beyond the control of Vegetation Management.

Harm: Personal injury or death, property damage, or disruption of activities.

Hazard Condition: A vegetation condition affecting transmission or distribution lines which does not pose an imminent threat, but where the condition has the potential to become an imminent threat and is at or encroaching the PG&E clearance distance.

Hazard Tree: A tree identified as a likely source of harm.

Lean: The predominant angle of the trunk from vertical.

Limited Visual Assessment (Level 1): A visual assessment from a specified perspective such as a foot, vehicle or aerial (airborne) patrol of an individual tree or a population of trees near specified targets to identify conditions or obvious defects of concern.

- Walk-by: A limited visual inspection, usually from one side of the tree, performed as the tree risk assessor walks by the tree(s).

- Drive-by/windshield assessment: A limited visual inspection from only one side of the tree, performed from a slow-moving vehicle.

- Aerial patrol: Overflights of a utility right-of-way, large areas, or individual trees in a defined area to record the location of trees that are likely to fail and cause harm.

Major Woody Stem (MWS): A trunk or limb at least 6 in. in diameter at the conductor level, on a tree at least 10 in. DBH and at least 10 years old.

Minimum Distance Requirement: Distance to maintain separation between vegetation and distribution conductors in Local Responsibility Areas (LRAs), State Responsibility Areas (SRAs) and California's High Fire Threat District (HFTD), in accordance with CPUC General Order (G.O.) 95, Rule 35 and Public Resource Code (PRC) 4293.

Priority: Conditions that may result from either encroachment into the Pacific Gas and Electric Company (PG&E) minimum clearance requirement or from potential tree or limb failure. The following time constrains apply to each of the priority conditions:

- Priority 1 tags must be mitigated within 24 hours of identification when reported.
- Priority 2 tags must be mitigated within 20 business days, unless constrained.

Refusal: A situation that occurs when a customer / property owner refuses to allow PG&E to perform pre-inspection work or complete 100% of the work prescribed.

Service Drop: The low-voltage (generally 110 to 750 volts) electric supply lines that connect end users to an electric distribution supply network. (ISA)

Strain: Is present when vegetation contact significantly compromises the structural integrity of supply or communication facilities. Contact between vegetation and conductors is not considered strain.

IMPLEMENTATION RESPONSIBILITIES

The VM Communication and Training team is responsible for issuing the communication associated with this procedure to the target audience and maintaining the accuracy of applicable training material.

The leadership of the target audience is responsible for holding the target audience accountable to performing the procedure as written.

The Document Contact(s) are subject matter or technical expert(s) who can answer questions about the procedure.

The Document Owner is responsible for maintaining accuracy of this procedure.

GOVERNING DOCUMENT

TD-7102S, Vegetation Management Distribution Program

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Records and Information Management:

Information or records generated by this procedure must be managed in accordance with the Enterprise Records and Information (ERIM) program Policy, Standards and Enterprise Records Retention Schedule (ERRS). REFER GOV-7101S, "Enterprise Records and Information Management Standard" and related standards. Management of records includes, but is not limited to:

- Integrity
- Storage
- Retention and Disposition
- Classification and Protection

California Public Utilities Commission (CPUC), General Order 95, Rule 35

California Public Utilities Commission (CPUC), General Order 95, Rule 35 in Appendix E

California Public Utilities Commission (CPUC), CPUC General Order 95, Rule 18

California Public Resources Code (PRC), sections 4293 and 4295.5

California Code of Regulations (CCR), Title 14, section 1257, "Exempt Minimum Clearance Provisions – PRC 4293"

REFERENCE DOCUMENTS

Developmental References:

TD-7102S, Vegetation Management Distribution Program

California Power Line Fire Prevention Field Guide, 2021 edition

Supplemental References:

TD-7102P-09, "Reporting Abnormal Field Conditions Procedure."

TD-7102P-17, "Vegetation Management Priority Tag Procedure"

TD-7103P-09, "Transmission Vegetation Management Hazard Notification Procedure."

TD-7102P-04, "Distribution Vegetation Refusal Procedure."

TD-7102P-08, "Facility Protect and Work Difficulty Classification Procedure."

TD 2014P-01, "Notification of Conditions to Third-Party Utility Procedure."

TD 2015P-01, "Notification of Conditions to Non-Utility Third-Party Procedure."

International Society of Arboriculture (ISA) Best Management Practices (BMPs)

ANSI A300 Part 9, "Tree Risk Assessment Standard," by E. Thomas Smiley, Nelda Matheny, and Sharon Lilly and its companion publication, "Utility Tree Risk Assessment," by John W Goodfellow, that describes the levels and scope of tree risk assessment.

Cal Fire Power Line Fire Prevention Field Guide

Utility Arborist Association (UAA) Best Management Practices for Tree Risk Assessment and Abatement

Utility Standard RISK-6300S, "Quality Management Audit Standard"

Utility Standard TD-2459S, "Management of Idle Electric Distribution Lines"

TD-2014S, "Third-Party Notification and Resolution of Potential Violations and Safety Hazards"

TD-2015S, "Notification to Third-Party Non-Utility of Nonconformance"

APPENDICES

Appendix A, "Minimum Distance Requirements"

Appendix B, "Overview of Tree Defects and Site Conditions"

Appendix C, "Second Patrol Defined Geographic Area"

Appendix D, "Bi-Annual Considerations"

Appendix E, "Tree Marking Colors"

Appendix F, "Information about Tree Lean"

ATTACHMENTS

TD-7102P-01-Att01 "Attachment 1, Strategies to Manage and Reduce Palms"

TD-7102P-01-Att02 "Attachment 2, EVM WMP Commitments"

TD-7102P-01-Att03 "Attachment 3, Identifying Major Woody Stems"

TD-7102P-01-Att04 "Attachment 4, Handling Stump Resprouts"

TD-7102P-01-Att05 "Attachment 5, Bi-Annual Tree Management and Reduction Strategy"

TD-7102P-01-JA01, "Best Management Practices (BMP) for Vegetation Management Activities"

Vegetation Management Distribution Inspection Procedure

DOCUMENT RECISION

TD-7102P-01, "Vegetation Management Distribution Routine Patrol Procedure (DRPP)," 10/27/2015, Rev. 1 (original publication)

TD-7102P-01-B026, "EVM Transition to Distribution Routine Patrol," 09/13/2021, Rev. 0

TD-7102P-01-B028, "Overhanging Vegetation Clearances," 10/26/2022, Rev. 0

TD-7107S, "Vegetation Management Marking Standard," 01/28/2021, Rev. 0

TD-7102P-05, "Major Woody Stem Exemption," 01/12/2018, Rev. 2

TD-7102P-05-B023, "Changes to Major Woody Stem Exemption Procedure," 06/15/2020, Rev. 0

TD-7102P-23, "Vegetation Management Second Patrol Procedure," 07/13/2019, Rev. 2

TD-7106P-01, "Enhanced Vegetation Management Pre-Inspection Procedure," 05/12/2020, Rev. 0

TD-7106P-01-B001, "Change Control Process for EVM Non-Regulatory Commitments," 4/28/2022, Rev. 0

DOCUMENT APPROVER

Michael Seitz, VP, Vegetation Management

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DOCUMENT CONTACT

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REVISION NOTES

Where?	What Changed?
Entire document	Completely rewritten to streamline and bring procedures current as of 31 December 2022. Moved information about palms, orchards, bi-annuals, stump resprouts to attachments. Added information about major woody stems.

Appendix A, Minimum Distance Requirements (MDR)

Page 1 of 1

Jurisdiction	LRA (non-HFTD) Applicable year-round	HFTD Applicable year-round	SRA Applicable during fire season	FRA (When on USFS property) Applicable during fire season
Regulation	G.O. 95, Rule 35	G.O. 95, Rule 35	PRC 4293	PRC 4293
Minimum Distance Requirement for Primary Conductors greater than 750 volts	18-inches	4-feet	4-feet	4-feet
Requirement for Conductors less than 750 volts	Prune if strain or abrasion to the conductor is observed.			

- If LRA overlaps with HFRA PG&E MDR guidance is consistent with HFTD requirements, unless otherwise constrained.
- If FRA is not on USFS Property, PG&E MDR guidance is consistent with HFTD requirements, unless otherwise constrained.
- Vegetation must not encroach within the minimum distance at any time between inspection and one year or next scheduled Inspection Cycle.
- Depending on span length, facility construction and conductor material, potential sag and sway can range from 1-foot at quarter-span to 4-feet at mid-span.

Appendix B, Overview of Tree Defects and Site Conditions

Page 1 of 2

The Hazard Trees/Vegetation Clearance section of the "California Power Line Fire Prevention Field Guide" provides information on tree defects and site conditions that increase the likelihood of tree failure. Below is a non-exhaustive list from that document.

- Standing dead trees and dead parts of trees
- Broken and/or hanging branches
- Cracks
- Weakly attached branches or codominant stems
- Decayed or missing wood (damage or cankers)
- Unusual tree architecture (lean, balance, branch distribution, or lack of taper)
- Loss of root support
- Shallow soils
- Insect infestation
- Diseases
- Suppressed or intermediate stems within a forest stand
- Fire damage
- Fruiting bodies of known wood decay fungus
- Narrow attachment with included bark
- Dwarf Mistletoe and Rust Cankers (conifers)
- Bleeding
- Dying
- Rot

Appendix B, Overview of Tree Defects and Site Conditions
Page 2 of 2

When assessing for heart/butt rot, the assessment should include but not be limited to the following items:

- Open wounds showing visible rot
- Old wounds that have partially or fully healed over
- Conks anywhere on the bole of the tree
- Hollow trunks detected by rapping on the tree trunk or by use of an increment borer
- Decreasing crown vigor
- Cracks or splits not caused by lightning
- Swelling or cankers on the bole
- Wildlife cavities
- Presence of carpenter ants or termites
- Number, size, and distribution of fungal fruiting bodies
- Broken or dead tops
- The amount of solid radial wood remaining where visible
- Poor live crown ratio (% live crown)
- Poor diameter-to-height ratio

Appendix C, Second Patrol Defined Geographic Area
Page 1 of 1

Inspection area details

- **State Responsibility Area (SRA):** The area in the state where the State of California (CAL FIRE) has the primary financial responsibility for the prevention and suppression of wildland fires.
- **Federal Responsibility Area (FRA):** Those lands administered or controlled by the Federal Government for which the Federal Agencies have administrative and protection responsibility.
- **High Fire-Threat District (HFTD):** High Fire-Threat District means those areas comprised of the following:(1) Zone 1 is Tier 1 of the latest version of the United States Forest Service (USFS) and CAL FIRE's joint map of Tree MortalityHigh Hazard Zones (HHZs). (Note: The Tree Mortality HHZs Map may be revised regularly by the USFS and CAL FIRE.)
    - (2) Tier 2 is Tier 2 of the CPUC Fire-Threat Map.
    - (3) Tier 3 is Tier 3 of the CPUC Fire-Threat Map.
- **High Fire Risk Area (HFRA):** A purpose-built map for use in scoping Public Safety Power Shutoff events identifying areas where risk factors for the potential of catastrophic fire from utility infrastructure ignition during offshore wind events is higher.
- **Wildland Urban Interface (WUI):** Layer produced by Silvis Labs that clipped to Local Responsibility Areas (LRA). Intermix WUI are areas where housing and vegetation intermingle; interface WUI are areas with housing in the vicinity of contiguous wildland vegetation.
- **Fire Hazard Severity Zone (FHSZ):** A layer produced by CAL FIRE and the Resource Assessment Program (FRAP) using data and models describing development patterns, potential fuels over a 30-50 yeartime horizon, expected fire behavior, and expected burn probabilities, to quantify the likelihood and nature of vegetation fire exposure. This second patrol project pertains only to the very high fire severity zone within the LRA.

Appendix D, Tree Marking Colors

Page 1 of 2

Programs are assigned the marking colors and patterns shown in the table. One color can be assigned to several programs. The sample column is approximate and illustrative only. The paint brands and color names shown in the table comply with this standard.

Program	Color	Sample	Paint Brand and Color Name
• Distribution program years: 2020, 2024, 2028 • Transmission program years: 2022, 2026, 2030	Orange		• Nelson Aero Spot: Orange • Aervoe: Orange • Aervoe Professional Choice: Orange
• Distribution program years: 2021, 2025, 2029 • Transmission program years: 2023, 2027, 2031	Light Green		• Nelson Aero Spot: Lite Green
• Distribution program years: 2022, 2026, 2030 • Transmission program years: 2020, 2024, 2028	Red		• Nelson Aero Spot: Red • Aervoe: Red • Aervoe Professional Choice: Red
• Distribution program years: 2023, 2027, 2031 • Transmission program years: 2021, 2025, 2029	White		• Nelson Aero Spot: White • Aervoe: White • Aervoe Professional Choice: White
• Fire and storm response	Fluorescent Green		• Nelson Aero Spot: Green Glo • Aervoe: Fluorescent Green • Aervoe Professional Choice: Fluorescent Green
• Estimating arborist	Pink		• Nelson Aero Spot: Pink Glo • Aervoe: Fluorescent Hot Pink
• Transmission reliability (TVMR)	Blue		• Nelson Aero Spot: Lite Blue • Aervoe Professional Choice: Light Blue
• Enhanced vegetation management (EVM) • Fuel reduction • Second patrol/CEMA	Yellow		• Nelson Aero Spot: Yellow • Aervoe: Yellow • Aervoe Professional Choice: Yellow
• Cover paint	Black		• Nelson Aero Spot: Black • Aervoe: Black
	Brown		• Nelson Aero Spot: Brown
• Work Verification	Pink with a pattern	Examples:   (flagging only)	

Appendix D, Tree Marking Colors
Page 2 of 2

1 Unassigned Colors (Informative)

Some colors are not yet assigned to a program. The sample column is approximate and illustrative only. This appendix is informative only.

Program	Color	Sample	Paint Brand and Color Name
• None	Fluorescent Orange		• Nelson Aero Spot: Orange Glo • Aervoe Professional Choice: Fluorescent Orange
• None	Fluorescent Red		• Nelson Aero Spot: Red Glo • Aervoe: Fluorescent Red
• None	Fluorescent Blue		• Nelson Aero Spot: Blue Glo • Aervoe Professional Choice: Fluorescent Blue
• None	Purple		• Nelson Aero Spot: Purple
• None	Light Purple		• Nelson Aero Spot: Lite Purple
• None	Gray		• Nelson Aero Spot: Gray

2 Marking Errors (Informative)

The following actions are marking errors. This appendix is informative only.

- Painting a crumbly dirt hillside (cut bank) below a tree.
- Getting paint on a road or curb or fence (which could be considered graffiti).
- Flagging that is not the current cycle's color.
- Flagging on surrounding vegetation (e.g., blackberry bushes around an oak tree that requires work).

3 Discontinued Markings (Informative)

Some markings have been discontinued. This appendix is informative only.

•• Two dots meant facility protect.

SE SE meant special equipment. Instead, the need for special equipment or methods is recorded in the tree record.

Vegetation Management Distribution Inspection Procedure

Appendix E, Information about Tree Lean

Page 1 of 1

The following is taken from the California Power Line Fire Prevention Field Guide, 2021 edition.

Hazard Trees/Vegetation Clearance/Steps to Inspection/Lean (page 44)

Trees with more than a slight lean away from utility infrastructure are unlikely to strike the infrastructure, regardless of their weight distribution. Within reasonably foreseeable field conditions, such trees are generally not hazardous to infrastructure. Otherwise, the direction and amount of lean should be carefully evaluated.

Trees exhibit either corrected or uncorrected lean. Corrected lean is usually exhibited in hardwood trees that naturally grow in a non-linear fashion (decurrent) or in conifers that grow upright (excurrent) after a force has moved the bole off vertical (like snow-loading). Corrected lean may not constitute a structural weakness in a tree.

Uncorrected lean is usually caused by outside factors (wind, soil conditions, etc.) that loosen or break roots. Construction activities that sever roots or strike tree butts and boles also cause trees to lean, as does the impact of falling trees, either natural or human caused. Humps and soil mounding on the opposite side of the lean direction are often indicators of broken or loosened tree roots. Cracks in the bole and roots are often signs of a failure in progress, and abatement may be required right away.

A leaning tree can be more hazardous because of the presence of open fire wounds or cankers, especially if accompanied by rot.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT I

UTILITY PROCEDURE: TD-7102P-01 VEGETATION MANAGEMENT DISTRIBUTION PROCEDURE ATT 4, HANDLING STUMP RESPROUTS

Vegetation Management Distribution Inspection Procedure

Attachment 4, Handling Stump Resprouts

The Vegetation Management Inspector (VMI) must prescribe stump treatment when removing re-sprouting species, unless specifically denied by the property owner, land manager, or regulations.

1.1 The VMI must PERFORM the following steps.

1. VERIFY stump death of past removals from previous patrols for all re-sprouting species during current routine patrol.

2. ATTEMPT TO GET permission when using herbicides if you don't prescribe for routine work.

3. LIST all re-sprouting stumps for tree re-work in the system of record when the following conditions are met:

   - Stump is or will become a compliance issue in the future, regardless of time frame.

   - Herbicide treatment was prescribed and customer, agency, or local ordinances approve the herbicide application.

   - Herbicide will not translocate to other living vegetation.

   - Re-sprouts are not root sprouts.

4. DELETE the tree record when the stump is verified as dead.

5. NOTIFY the customer of re-treat in person or with door card.

6. When the TC notifies the VMI of locations where herbicide treatments cannot be applied, UPDATE the system of record and ADD comments.

1.2 The TC must PERFORM the following steps.

1. RE-TREAT and KILL any re-sprouts that have been prescribed the "TRT" trim code during routine activities.

2. VERIFY that herbicide treatments have resulted in the death of the stump.

3. NOTIFY the VMI when re-sprouts have been prescribed for re-treat work and the stump cannot be treated.

4. Enter NO WORK on the Work Request.

5. PRUNE the stump re-sprout unit when the unit cannot be re-treated and will be non-compliant before the next routine cycle.

Vegetation Management Distribution Inspection Procedure

Attachment 4, Handling Stump Resprouts

Step 1.2 (continued)

6. DOCUMENT and INVOICE the unit as an “add.”

End of Instruction

REVISION NOTES

Where?	What Changed?
NA	Original publication.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT J

VEGETATION MANAGEMENT WORK LONG-TERM BENEFIT EXAMPLES

Vegetation Management Work Long-Term Benefit Examples

Directional Pruning: Benefits

Sample 1 illustrates long-term benefits of directional pruning on a deciduous oaks in PG&E's Sierra division. Achieving significant clearance distances in combination with proper ANSI A300 pruning techniques can yield long–term, multiple year benefits for public safety, compliance and reliability, as well as maintenance cost savings.

While certain trees can resprout following pruning, a proper prune can drastically minimize re-encroachment for multiple years.

Sample 1: Oak Directional Side Prune

Sample 2 illustrates long-term benefits of large clearance side pruning on conifer species (ponderosa pine) in PG&E's Sierra division. Achieving significant clearance distances in combination with proper A300 pruning techniques can yield long–term multiple year benefits for public safety, compliance and reliability, as well as maintenance cost savings.

Most conifer species do not resprout following proper pruning, yielding long-term public safety, compliance, and reliability benefits, as well as maintenance cost savings.

Sample 2: Conifer Directional Side Prune

Removal Benefits: Coast Live Oak Trees


Sample 3a: Coast Live Oak removal span looking south


Sample 3b: Coast Live Oak removal span looking north


Sample 3c: Removal stump with regrowth

Certain native and non-native tree species cannot be mitigated for the long-term without tree removal. While the removals yield long-term benefits, there may additional maintenance needs – though at a lower cost. Long-term benefits and cost reduction of maintenance can be achieved through proactive management following removal to manage regrowth and resprouting while the vegetation remains low to the ground and well away from electrical conductors.

Drivers for Tree Removal


Sample 4a: Coast live oak Directional Side/Top Prune. Established large diameter tree.

Even with significant clearances and proper pruning, certain species of trees in regions within the PG&E territory may require a combination of proactive pruning and maintenance strategies to ensure long-term benefits.

Samples 4a and 4b illustrate regional challenges to achieve long-term benefits with directional pruning alone. In these circumstances, it is better to proactively manage trees before maturity through **removal**. This yields benefits longer in duration and cost savings.


Sample 4b: Coast live oak Directional Side/Top Prune. As shown, there is a large clearance of canopy still subject to regrowth and annual pruning. In these cases, certain species are better managed in advance of maturity through removal and maintenance rather than annual pruning to yield long-term benefits and cost savings.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

TAXATION

WITNESS: TIM B. WEDLAKE

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CHAPTER 5
TAXATION
WITNESS: TIM B. WEDLAKE

A. Introduction

This chapter describes the tax implications of Pacific Gas and Electric Company's (PG&E or the Utility) proposed ratemaking for the costs associated with the Wildfire Rate Relief Fixed Recovery Charge (WRRFRC), and the tax items to be included in the associated Fixed Recovery Tax Amounts (FRTA).

In this chapter, PG&E:

- Describes the normalized ratemaking treatment associated with the WRRFRC, which will be included in the FRTA; and
- Notes that the WRRFRC does not securitize any capex and thus the flowthrough tax repairs deduction and the associated tax repairs flowback ratemaking treatment will not be included in this FRTA.

B. Tax Treatment of Securitization

As described in Chapter 2, Background on Utility Securitization (K. Niehaus), Revenue Procedure 2005-62 clarifies that a Qualifying Securitization is not recognized as gross income to the Utility when it receives the financing order or proceeds of the securitization bonds. Instead, securitization related customer charges are recognized as income to the Utility as they are collected over time under its usual method of accounting. Article 5.8 of the California Public Utilities Code (Pub. Util. Code) states that the California Public Utilities Commission may allow "fixed recovery tax amounts" for any portion of the electrical corporation's federal and state of California income and franchise taxes associated with the fixed recovery charges, and not financed from proceeds of recovery bonds.[1] While taxes over the life of the bonds will net to zero, there will be timing differences that require the need for a separate FRTA.

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[1] Pub. Util. Code § 850.1(a)(1)(B).

This is because the WRRFRC that will be collected from customers, which is taxable income when PG&E receives it, will be offset in different periods by certain expenditures that are deductible. The expenditures analyzed include:

1) Interest on the Wildfire Rate Relief Bond – tax deductible as incurred;
2) Upfront Financing Costs, as described in Chapter 3, Transaction Overview (M. Klemann) – tax deductible straight-line- over the life of the Wildfire Rate Relief Bond; and
3) Ongoing Financing Costs as described in Chapter 3, Transaction Overview (M. Klemann) – tax deductible as incurred.[2]

The amortization of Upfront Financing Costs occurs at a different time from when the taxable revenue is collected from customers, resulting in a net cash flow surplus in earlier years that will be reduced over time by net cash flow deficits in later years. Although the Upfront Financing Costs tax amortization uses the same anticipated amortization period as the Wildfire Rate Relief Bonds, the tax method (straight-line) is accelerated as compared to the mortgage style amortization (backloaded) used for books to compute revenue collected from customers, resulting in an accumulated deferred income tax (ADIT) in the earlier years. For the other categories of expenditures considered (numbers 1 and 3 above), the tax deduction is equal to the book expense within the same period, resulting in no net tax and associated cash flow impact. PG&E has included interest on the ADIT liability as reflected on line 10 of Attachment C to Chapter 3, Transaction Overview (M. Klemann) in the FTRA. PG&E will include the FRTA within the balancing account associated with the Wildfire Rate Relief Bonds and WRRFRC discussed in Chapter 6, Ratemaking Mechanisms (S. Sims), to provide customers the benefit of the interest on the ADIT.

C. Conclusion

The proposed ratemaking mechanisms described in this chapter are necessary to accurately reflect the normalized tax treatment of the costs reflected in the FRTA and included in the WRRFRC.

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[2] The Ongoing Financing Costs are estimated in Attachment B to Chapter 3. The line item contained therein for “Return on Equity Contribution to SPE” is not tax deductible.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

RATEMAKING MECHANISMS

WITNESS: SHANNON L. SIMS

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PACIFIC GAS AND ELECTRIC COMPANY
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RATEMAKING MECHANISMS
WITNESS: SHANNON L. SIMS

A. Introduction

This chapter describes Pacific Gas and Electric Company's (PG&E) proposed ratemaking for the costs associated with the Wildfire Rate Relief Bonds, the Wildfire Rate Relief Fixed Recovery Charge (WRRFRC), which is a subcomponent of the existing Wildfire Hardening Fixed Recovery Charge (WHFRC), and use of the Wildfire Hardening Fixed Recovery Charge Balancing Account (WHFRCBA) for the Wildfire Rate Relief Bonds. PG&E proposes these mechanisms to assure repayment of the Wildfire Rate Relief Bonds and to provide for the recovery of other costs associated with the Wildfire Rate Relief Bond-related transactions. These mechanisms are similar to those already approved in Decision (D.) 21-06-030, D.22-08-004, and D.24-02-011, which authorized PG&E to finance fire risk mitigation capital expenditures in the Initial, Second, and Third Assembly Bill (AB) 1054 Securitizations through the issuance of Wildfire Hardening Recovery Bonds.

B. Background

The ratemaking proposed in this chapter is similar to the treatment approved in PG&E's Initial, Second, and Third AB 1054 Securitization proceedings, Application (A.) 21-02-020, A.22-03-010, and A.23-08-009, with limited adjustments to reflect the treatment of the credit for previously collected revenue as further described below in Section D. On February 24, 2021, PG&E filed A.21-02-020 and submitted supporting testimony requesting authority for an initial issuance of Wildfire Hardening Recovery Bonds totaling up to approximately $1.2 billion, consisting of up to $1.19 billion to fund AB 1054 fire risk mitigation capital expenditures (CapEx) and $13.3 million in upfront financing costs.[1] On June 24, 2021, the California Public Utilities Commission

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[1] Chapter 5, Ratemaking Mechanisms (B. Smith), of A.21-02-020 described PG&E's proposed ratemaking associated with the Initial AB 1054 Securitization.

(CPUC or Commission) issued D.21-06-030, approving PG&E's request.[2] D.21-06-030 approved PG&E's request to establish a nonbypassable Fixed Recovery Charge[3] (i.e., the Wildfire Hardening Fixed Recovery Charge (WHFRC)) collected from customers to pay back the bonds and establish a new WHFRCBA to record costs and benefits for subsequent recovery from or credit to customers related to costs and credits that are not included in the WHFRC, and amounts needed to pay any taxes imposed on the WHFRCs or the tax implications associated with the assets financed with the Wildfire Hardening Recovery Bonds.[4] PG&E filed Advice Letter (AL) 6372-E to establish the WHFRC and WHFRCBA on October 22, 2021.[5]

On March 11, 2022, PG&E filed A.22-03-010, requesting authority for a second issuance of Wildfire Hardening Recovery Bonds up to a combined principal amount of approximately $1.7 billion, consisting of $1.369 billion in capital expenditures approved in PG&E's 2020 General Rate Case (GRC) and approximately $350 million of Wildfire Mitigation and Catastrophic Events (WMCE) CapEx then pending in the WMCE Proceeding. On April 27, 2022, the CPUC issued a Scoping Memo directing PG&E to remove the WMCE CapEx from the Second AB 1054 Securitization because it was unlikely that a final decision in the WMCE Proceeding was going to be issued prior to issuance of the financing order for the Second AB 1054 Securitization. On August 5, 2022, the CPUC issued D.22-08-004 authorizing PG&E to issue Wildfire Hardening Recovery Bonds totaling up to approximately $1.4 billion.[6] Similar to the authority granted in the Initial AB 1054 Securitization proceeding, D.22-08-004 approved: (1) the recovery through nonbypassable Fixed Recovery Charges (the WHFRC),[7] and (2) the continued use of the WHFRCBA.[8]

On August 10, 2023, PG&E filed A. 23-08-009, requesting authority for a third issuance of Wildfire Hardening Recovery Bonds of up to a total principal

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2 See D.21-06-030 at 115 (Ordering Paragraph (OP) 1.a.).

3 See *Id.* at 115-116 (OP 1.d.).

4 See *Id.* at 116 (OP 1.e.).

5 Advice 6372-E was approved effective November 21, 2021.

6 See D.22-08-004 at 110 (OP 1.a.).

7 See *Id.* at 111 (OP 1.d.).

8 See *Id.* at 111 (OP 1.e.).

amount of approximately $1.4 billion, consisting of capital expenditures approved in PG&E's 2020 and 2023 GRCs and 2020 WMCE proceeding, Pre-Securitization Debt Financing Costs, and Upfront Financing Costs. On February 16, 2024, the CPUC issued D.24-02-011 authorizing PG&E to issue Wildfire Hardening Recovery Bonds totaling up to approximately $1.4 billion.[9] Similar to the authority granted in the first two AB 1054 Securitization proceedings, D.24-02-011 approved: (1) the recovery through nonbypassable Fixed Recovery Charges (the WHFRC),[10] and (2) the continued use of the WHFRCBA.[11]

C. Ratemaking Treatment of the Wildfire Rate Relief Fixed Recovery Charge

The proposed ratemaking mechanisms described in this chapter are necessary to assure repayment of the Wildfire Rate Relief Bonds and accurate accounting for the Wildfire Rate Relief Bonds-related transactions. The structure is similar to those proposed in A.21-02-020, A.22-03-010, and A.23-08-009 and approved in D.21-06-030, D.22-08-004, and D.24-02-011, respectively.

1. Wildfire Rate Relief Fixed Recovery Charge

As requested in the application, PG&E proposes to issue one or two series of Wildfire Rate Relief Bonds up to the Authorized Amount. Similar to the WHFRC[12] approved for PG&E's Initial AB 1054 Securitization, Second AB 1054 Securitization, and Third AB 1054 Securitization, each series of Wildfire Rate Relief Bonds would have its own FRC. The WRRFRC will appear as a subcomponent of the existing WHFRC.[13] PG&E expects to

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9 See D.24-02-011 at 113 (OP 1.a.).

10 See *Id.* at 114 (OP 1.d.).

11 See *Id.* at 114 (OP 1.e.).

12 See D.21-06-030 at 115-116 (OP 1.d.); D.22-08-004 at 111 (OP 1.d); D.24-02-011 at 114 (OP 1.d).

13 See [Electric Preliminary Statement Part JF.]

submit an Issuance AL[14] to set rates for the WRRFRC within one day after the Wildfire Rate Relief Bonds are priced. Repayment of each series of Wildfire Rate Relief Bonds would be accomplished through the WRRFRC associated with that series. The revenues received from the WRRFRC would be transferred to the Bond Trustee for the benefit of the Special Purpose Entity (SPE) to be applied against the financing costs for that series of Wildfire Rate Relief Bonds. Financing costs include:

- Scheduled debt service (principal and interest) on the issuance of Wildfire Rate Relief Bonds;
- Upfront Financing Costs (i.e., Bond issuance costs);
- Bond Trustee fees;
- Servicing and administration fees;[15]
- Replenishing the capital subaccount;
- Other Ongoing Financing Costs;
- Credit enhancements to the extent required by the rating agencies; and
- Other costs as specifically authorized by a financing order.

These financing costs and an allowance for uncollectibles are components of the WRRFRC. See Attachment A to Chapter 7, Rate Proposal (B. Kolnowski), for illustrative rates of the WRRFRC.

As discussed in more detail in Chapter 3, Transaction Overview (M. Klemann), and consistent with the process approved by the Commission for the first three AB 1054 Securitizations, PG&E requests that the Commission adopt in the Financing Order a procedure to allow PG&E to submit Routine True-Up Mechanism ALs at least annually to adjust the

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14 A pro forma Issuance AL is Attachment 2 to the Form of Financing Order attached to the application. The Issuance AL would use the securitized bond revenue requirement calculations, presented in Attachment C to Chapter 3, Transaction Overview (M. Klemann), for each series of Wildfire Rate Relief Bonds, along with the most recent PG&E sales forecast for the relevant time period, and current terms for the Wildfire Rate Relief Bonds and amounts for Upfront Financing Costs and Ongoing Financing Costs, to develop the initial WHFRC for that series of Wildfire Rate Relief Bonds.

15 The Bond Trustee uses the servicing fee and administration fee components incorporated into the WHFRC to pay the servicing fee and administration fee for that series of Wildfire Rate Relief Bonds to the servicer and administrator, PG&E.

WRRFRC.[16] These ALs are intended to ensure that the actual revenues collected under the WRRFRC are neither more nor less than those required to repay the Wildfire Rate Relief Bonds and pay other allowed costs as scheduled. As authorized in the first three AB 1054 Securitizations, PG&E also proposes to submit Non-Routine True-Up Mechanism ALs to reflect revisions to the logic, structure, and components of the cash flow model and resulting adjustments to the WRRFRC and/or fixed recovery tax amounts (FRTA).[17]

The WRRFRC would reflect the following:

a) The Periodic Payment Requirement;[18]

b) Forecasted sales for the remainder of the current year and of the subsequent year, if applicable, of the transaction would be revised to reflect PG&E's latest estimate of sales (see further discussion in Chapter 7, Rate Proposal (B. Kolnowski));

c) As discussed in more detail in Chapter 7, Rate Proposal (B. Kolnowski), and consistent with D.21-06-030, D.22-08-004, D.24-02-011, and the RA Settlement Agreement approved in D.21-11-016, revenue allocation of the WRRFRCs will be adjusted to reflect changes in sales to collect the revenue requirement;[19]

d) Estimated Ongoing Financing Costs will be modified to reflect changed circumstances (see further discussion in Chapter 3, Transaction Overview (M. Klemann));

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[16] D.21-06-030 authorized PG&E to submit annual Routine True-Up Mechanism ALs. See D.21-06-030 at 125-126 (OP 33). See also D.22-08-004 at 120-21 (OP 33) and D.24-02-011 at 124 (OP 33).

[17] See D.21-06-030 at 126 (OP 34) (authorizing PG&E to submit Non-Routine True-Up Mechanism ALs); D.22-08-004 at 121 (OP 34).

[18] As defined in Chapter 3 Transaction Overview (M. Klemann), the Periodic Payment Requirement would be (i) increased or decreased by the amount by which actual remittances of WRRFRC revenues to the Bond Trustee collection account through the end of the month preceding the month of calculation was less than or exceeded the Periodic Payment Requirement for the prior period, and (ii) to the extent not included in (i), decreased by the amount projected to be held in the excess funds subaccount at the beginning of the next payment period.

[19] As discussed in Chapter 7, consistent with D.21-06-030, D.22-08-004, and D.24-02-011, the revenue allocation methodology for the bonds should remain the same for the life of the bonds, with adjustments for sales changes to collect the revenue requirement.

e) Assumed uncollectibles will be modified to equal the percentage of losses actually experienced during the most recent 12-month billing period for which such information is available; and

f) An adjustment will be made to reflect collections that will be received at the existing tariff rate from the end of the month preceding the date of the calculation through the end of the month in which the calculation is done.

A pro forma preliminary statement of the proposed modification to the WHFRC to add on the new rates associated with the Wildfire Rate Relief Bonds is included in Attachment A.

2. Wildfire Hardening Fixed Recovery Charge Balancing Account

As a result of the issuance of Wildfire Rate Relief Bonds, various miscellaneous costs and savings will accrue to customers. The WHFRCBA, which was established in PG&E's Initial AB 1054 Securitization,[20] will record those costs and benefits for subsequent recovery from or credit to customers. The WHFRCBA includes the servicing fee and administration fee amounts paid to PG&E in excess of the incremental cost of billing and collecting the WRRFRC and administering the SPE, the franchise fees associated with the WRRFRC, and interest on accumulated deferred income tax, as described in Chapter 5, Taxation (T. Wedlake).[21] Amounts necessary to adjust the otherwise adopted revenue requirement are described in Section D, below, and will be recorded in other balancing accounts. Disposition of the annual balance in the WHFRCBA will be through the Annual Electric True-Up (AET) AL process or through another rate change AL as approved by the Commission. A pro forma preliminary statement of the proposed modification to the WHFRCBA to add on the new rates associated with departing load customers associated with the Wildfire Rate Relief Bonds is included in Attachment A.

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20 See D.21-06-030 at 128 (OP 45). See Electric Preliminary Statement Part JG.

21 As noted above in Section C.1., the WRRFRC includes an estimate for uncollectibles expense. As a result, it does not need to be computed and recorded in the WHFRCBA.

D. Rate Credit Associated With Issuance of the Wildfire Rate Relief Bonds

The expenses to be financed through the Wildfire Rate Relief Bond issuance includes vegetation management Operation and Maintenance (O&M) expenses incurred in 2023 and 2024 or that will be incurred in 2024 that were adopted by the Commission in the 2023 GRC Decision. These expense amounts are being recorded into the Vegetation Management Balancing Account (VMBA).[22] Specifically, the VMBA is a one-way balancing account that tracks actual incurred expenses up to adopted imputed amounts over the entire GRC rate case cycle.[23] The revenues to collect the adopted VMBA amounts are recorded in the Distribution Revenue Adjustment Mechanism (DRAM). Upon issuance of the Wildfire Rate Relief Bonds, PG&E will record a credit entry to DRAM equal to its actual incurred vegetation management expenses financed using Wildfire Rate Relief Bonds to credit to customers through its next rate change AL following the bond issuance, as approved by the Commission. A pro forma preliminary statement with modifications to the DRAM is included in Attachment A.

E. Conclusion

The proposed ratemaking mechanisms described in this chapter are necessary to assure repayment of the Wildfire Rate Relief Bonds, assure accurate accounting for bond-related transactions, and provide customers with the benefits of the securitized financing of the Wildfire Rate Relief Bonds.

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22 See Electric Preliminary Statement Part BU.

23 PG&E will continue to track and record actual compared to adopted vegetation management expenses in the VMBA over the GRC rate case cycle. If PG&E is underspent in total at the end of the GRC cycle, PG&E will refund the underspent balance through its routine AET AL process.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT A

ELECTRIC PRELIMINARY STATEMENTS

CZ. DISTRIBUTION REVENUE ADJUSTMENT MECHANISM (DRAM)

1. PURPOSE: The purpose of the DRAM is to record and recover the authorized distribution revenue requirements and certain other distribution-related authorized costs. The DRAM will ensure dollar-for-dollar recovery of these Commission-authorized distribution amounts.

   Upon issuance of securitized debt under AB 1054 to fund capital expenditures related to spending during the period from August through December 2019, ongoing capital revenue requirements related to these capital expenditures will be modified to exclude depreciation expense, the return on investment, and taxes, with the exception of property taxes.

   Upon issuance of the Wildfire Rate Relief Bonds under AB 1054 to fund vegetation management expenses, PG&E will record a credit entry to DRAM equal to the securitized vegetation management expenses.

2. APPLICABILITY: The DRAM shall apply to all customer bills for service under all rate schedules and contracts for electric distribution service subject to the jurisdiction of the Commission, except for those rate schedules or contracts specifically excluded by the Commission.

3. REVISION DATE: Disposition of the balance in this account shall be determined through the advice letter process.

4. DISTRIBUTION RATES: The distribution rates are included in the effective rates set forth in each rate schedule.

5. ACCOUNTING PROCEDURES: The following entries shall be made each month, or as applicable. Note that all debits and credits described below, except for item 5.v., include an allowance for Revenue Fees and Uncollectible (RF&U) account expense.

   a. A debit entry equal to the annual authorized distribution revenue requirements divided by twelve.

   b. A debit or credit entry to adjust capital revenue requirements related to securitized capital expenditures to exclude depreciation expense, the return on investment, and taxes excluding property taxes.

   c. A credit entry equal to securitized vegetation management expenses.

   ~~c.~~d. A debit or credit entry equal to the total of the distribution-related regulatory account balances at the rates authorized in PG&E's most recent GRC, transferred to the DRAM, as authorized in the Electric Annual True-up Proceeding or other proceeding expressly authorized by the Commission.

   ~~d.~~e. A debit entry equal to the costs of the remaining customer education efforts associated with the Electric Education Trust (EET) per Decision 01-05-091, up to the amount authorized for PG&E by the Commission at the rates authorized in PG&E's most recent GRC.

   ~~e.~~f. A credit entry equal to the revenue from the distribution rates less the recorded California Public Utilities Commission Reimbursement Fee revenue (defined in Part E of PG&E's electric Preliminary Statement), the Demand Response Revenue Balancing Account revenue (defined in Part I of PG&E's electric Preliminary Statement), and the SmartMeter Balancing Account revenue (defined in Part I of PG&E's electric Preliminary Statement).

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART CZ Sheet 2
DISTRIBUTION REVENUE ADJUSTMENT MECHANISM

CZ. DISTRIBUTION REVENUE ADJUSTMENT MECHANISM (DRAM) (Cont'd.)

5. ACCOUNTING PROCEDURES: (Cont'd.)

g~~f~~. A credit entry equal to the debit entry in the California Alternate Rates for Energy Account (CAREA) that corresponds to the actual CARE revenue shortfall. The corresponding debit entry is defined in PG&E's electric Preliminary Statement Part M, Item 5a.

h~~g~~. A credit entry equal to the debit entry in the Family Electric Rate Assistance Balancing Account (FERABA) that corresponds to the actual FERA revenue shortfall for the California Solar Initiative. The corresponding debit entry is defined in PG&E's electric Preliminary Statement Part DX, Item 5.b.

i~~h~~. A credit entry equal to the recorded amount of revenue cycle services credits given to customers for revenue cycle services provided by entities other than PG&E.

j~~i~~. A credit entry equal to the amount of Shareholder Participation, as defined in Section 6 below.

k~~j~~. A debit entry equal to the payment to fund PG&E Environmental Enhancement Corporation, pursuant to the Chapter 11 Settlement Agreement Paragraph 17c adopted in Decision 03-12-035.

l~~k~~. A debit entry equal to one-twelfth of the current-year California Solar Initiative (CSI) revenue requirement authorized by the CPUC.

m~~l~~. A debit entry equal to one-twelfth of the electric portion of the Demand Response revenue requirement, as authorized by the CPUC.

n~~m~~. A credit or debit entry, as appropriate, to record any net activities resulting from bidding PG&E's Demand Response Programs into the CAISO.

o~~n~~. A debit or credit entry, as appropriate, to record any shareholder rewards or penalties under the Reliability Incentive Mechanism adopted in D.04-10-034.

p~~o~~. A debit entry equal to the amounts paid to the Commission for reimbursement of rate case expenses billed to the Utility pursuant to Public Utilities Code Section 631, plus an allowance for RF&U account expense.

q~~p~~. A debit entry equal to the intervenor compensation payments authorized by the Commission, recorded during the month.

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART CZ Sheet 3
DISTRIBUTION REVENUE ADJUSTMENT MECHANISM

CZ. DISTRIBUTION REVENUE ADJUSTMENT MECHANISM (DRAM) (Cont'd.)

5. ACCOUNTING PROCEDURES: (Cont'd.)

r~~g~~. A debit or credit entry, as appropriate, to record the gain or loss on the sale of an electric distribution non-depreciable asset, as approved by the Commission.

s~~r~~. A debit entry equal to the electric portion of incremental administrative costs and amounts written off as uncollectible associated with the payment deferral plan for qualifying citrus and other agricultural growers pursuant to Resolution E-4065 at the rates authorized in PG&E's most recent GRC for the incremental administrative costs.

t~~s~~. A debit entry equal to the costs that PG&E will reimburse the Division of Ratepayer Advocates (DRA) for work performed by the retained IT consultant(s) in Application (A.) 10-02-028 as authorized by the Commission, recorded during the month. The costs that PG&E will reimburse DRA shall not exceed $240,000 (excluding an allowance for RF&U), subject to revision by the Commission.

u~~t~~. A debit or credit entry, as appropriate, to record the aggregate net revenues collected from the Conservation Incentive Adjustment unbundled rate component of residential electric rates.

v~~u~~. A credit entry equal to the Family Electric Rate Assistance (FERA) revenue shortfall from paying residential Tier 2 rates for Tier 3 usage. The corresponding debit entry is defined in PG&E's electric Preliminary Statement Part DX, Item 5.a.

w~~v~~. A debit entry equal to one-twelfth of the authorized amount recorded in the California Energy Systems for 21st Century Balancing Account – Electric (CES21BA-E).

x~~w~~. A debit entry equal to one-twelfth of the annual revenue requirements recorded in the Smart Grid Line Sensor subaccount, Volt/VAR Optimization subaccount, and Detect & Locate Faults subaccount of the Smart Grid Pilot Deployment Project Balancing Account (SGPDPBA).

y~~x~~. A credit entry equal to the amount of employee transfer fees allocated to PG&E's electric ratepayers.

z~~y~~. A debit entry equal to one-twelfth of the authorized revenue requirement for the Residential Rate Reform Program. The corresponding credit entry is defined in PG&E's Electric Preliminary Statement Part GS, Residential Rate Reform Memorandum Account.

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART CZ Sheet 4
DISTRIBUTION REVENUE ADJUSTMENT MECHANISM

CZ. DISTRIBUTION REVENUE ADJUSTMENT MECHANISM (DRAM) (Cont'd.)

5. ACCOUNTING PROCEDURES: (Cont'd.)

aa~~z~~. A debit entry equal to the billed revenue for Schedule LS-1 decorative street light conversion to LED lights.

bb~~aa~~. A debit entry to record one-twelfth of the authorized annual revenue requirement, for the Transportation Electrification Balancing Account subaccounts associated with (1) the Charge Smart and Save Program, authorized in Decision (D.)16-12-065, (2) four Priority Review Projects and one evaluation expense subaccount, authorized in D.18-01-024, (3) the Direct Current Fast Charger (Fast Charge) Make-Ready Program, the Medium and Heavy-Duty Vehicle Charging (Fleet Ready) Program, and Program Evaluation expenditures approved in D.18-05-040, (4) the Empower Electric Vehicle Charger Incentive and Education Program, authorized in D.19-09-006, (5) the EV Charge Parks and EV Charge Schools Pilot Programs, authorized in D.19-11-01, (6) the three vehicle-grid integration pilots authorized in Resolution E-5192, (7) PG&E's portion of the third-party administered statewide transportation electrification infrastructure rebate program approved in D.22-11-040; and (8) the Transportation Electrification Advisory Services (TEAS) program, the proposal of which was authorized in D.21-07-028 and approved in Advice 6883-E, 6883-E-A, and 6883-E-B, by Resolution E-5314.

cc~~bb~~. A debit entry to record PG&E's prorata portion of the authorized Essential Usage Study (EUS) related revenue requirements, exclusive of the Enhanced Web Tool portion and inclusive of RF&U, over the period from when the revenue requirements begins and the completion of the schedule of activities. A corresponding entry is included in the EUSEBA, which excludes an allowance for RF&U.

dd~~cc~~. A debit entry to record PG&E's prorata portion of the authorized Enhanced Web Tool portion of the EUS related revenue requirements, inclusive of RF&U, over the period from when the revenue requirements begins and the completion of the schedule of activities. A corresponding entry is included in the EUSEBA, which excludes an allowance for RF&U.

ee~~dd~~. A debit entry equal to one-twelfth (or amortization period approved) of the electric distribution portion of the interim rate relief as authorized by the CPUC in D.19-04-039, D.20-10-026, or future interim rate relief Decisions as authorized by the Commission.

ff~~ee~~. A debit entry equal to the costs to charge the battery associated with the Llagas Energy Storage Project.

gg~~ff~~. A credit entry equal to the CAISO market revenues received, net of any related charges, for the Llagas Energy Storage Project.

hh~~gg~~. A debit entry to record one-twelfth (or amortization period approved) of the adopted Critical Peak Pricing related revenue requirement for the implementation of the new event hours, inclusive of RF&U, over the period from when the adopted revenue requirement begins and the completion of the schedule of activities. A corresponding entry is included in DREBA, which excludes an allowance for RF&U.

ii~~hh~~. A debit entry to record the delivery component of the customer bill savings from the Valley Clean Energy (VCE) Dynamic Rate Pilot.

jj~~ii~~. A debit entry to record one-twelfth of the authorized annual revenue requirement, inclusive of RF&U, for the Microgrids Balancing Account subaccounts associated with (1) the Make-Ready subaccount and (2) the Utility-Owned Generation subaccount. Corresponding entries are included in MGBA, which excludes an allowance for RF&U.

ELECTRIC PRELIMINARY STATEMENT PART CZ Sheet 5
DISTRIBUTION REVENUE ADJUSTMENT MECHANISM

CZ. DISTRIBUTION REVENUE ADJUSTMENT MECHANISM (DRAM) (Cont'd.)

5. ACCOUNTING PROCEDURES: (Cont'd.)

kk~~jj~~. A debit entry to record the distribution component of the customer bill savings from PG&E's Expanded Pilots.

ll~~kk~~. An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.

ELECTRIC PRELIMINARY STATEMENT PART JF Sheet 1
WILDFIRE HARDENING FIXED RECOVERY CHARGE (WHFRC)

JF. WILDFIRE HARDENING FIXED RECOVERY CHARGE (WHFRC)

1. PURPOSE:

The purpose of this section is to establish a Wildfire Hardening Fixed Recovery Charge, including a subcomponent Wildfire Rate Relief Fixed Recovery Charge, as mandated by Article 5.8 of the California Public Utilities Code (Article 5.8). Article 5.8 Section 850(a)(2) authorizes PG&E to recover a portion of its costs associated with fire risk mitigation capital expenditures and wildfire-related costs and expenditures (Wildfire Amounts) through the issuance of Wildfire Hardening Recovery Bonds and Wildfire Rate Relief Bonds. The Wildfire Hardening Fixed Recovery Charge is defined by Article 5.8 as a nonbypassable, separate charge that is authorized by the Commission in a Financing Order to recover costs and expenses related to catastrophic wildfires and financing costs associated with the Wildfire Hardening Recovery Bonds and Wildfire Rate Relief Bonds. The Wildfire Hardening Fixed Recovery Charge and subcomponent Wildfire Rate Relief Fixed Recovery Charge will be comprised of the following components: (1) scheduled debt service on the Wildfire Hardening Recovery Bonds and Wildfire Rate Relief Bonds, (2) administration and servicing fees, (3) Bond Trustee fees and other expenses, (4) any credit enhancements, (5) allowance for uncollectibles, (6) replenishing the capital subaccounts, and (7) other ongoing financing costs. A separate Wildfire Hardening Fixed Recovery Charge will apply to each series of Wildfire Hardening Recovery Bonds issued. A separate subcomponent Wildfire Rate Relief Fixed Recovery Charge will apply to each series of Wildfire Rate Relief Bonds issued. The aggregate amount of applicable Wildfire Hardening Fixed Recovery Charges and subcomponent Wildfire Rate Relief Fixed Recovery Charges will appear on customers' bills under one line item called "Wildfire Hardening Charge (WHC)."

The rights in and to the Wildfire Hardening Fixed Recovery Charge and subcomponent Wildfire Rate Relief Fixed Recovery Charge established pursuant to the Financing Order constitute "~~Wildfire Hardening~~ Recovery Property" as defined in the legislation and have been established pursuant to a Financing Order (FO), Decision 21-06-030, D.22-08-004, and D.24-02-011, issued by the California Public Utilities Commission. Concurrently with the effectiveness of the Wildfire Hardening Recovery Charge, PG&E has sold all of its rights with respect to such ~~Wildfire Hardening~~ Recovery Property to a special purpose entity, (~~[~~SPE)~~]~~, which is a wholly-owned subsidiary of PG&E formed to own the rights to the Recovery Property~~a Delaware Limited Liability Company (Special Purpose Entity)~~. The ~~Wildfire Hardening~~ Recovery Property includes the right, title, and interest of PG&E 1) in and to the Wildfire Hardening Fixed Recovery Charges and subcomponent Wildfire Rate Relief Fixed Recovery Charges, including all rights to obtain adjustments to the Wildfire Hardening Fixed Recovery Charges and subcomponent Wildfire Rate Relief Fixed Recovery Charges as provided in the Financing Order, and 2) to be paid the amount that is determined in the Financing Order that PG&E is lawfully entitled to receive pursuant to the provisions of Article 5.8 and the proceeds thereof, and all revenues, collections, claims, payments, money, or proceeds of or arising from Wildfire Hardening Fixed Recovery Charges and Wildfire Rate Relief Fixed Recovery Charges that are subject of the Financing Order. PG&E has no rights to the ~~Wildfire Hardening~~ Recovery Property, Wildfire Hardening Fixed Recovery Charge, Wildfire Rate Relief Fixed Recovery Charge, or any amounts payable thereunder.

2. APPLICABILITY:

This Wildfire Hardening Fixed Recovery Charge and subcomponent Wildfire Rate Relief Fixed Recovery Charge shall apply to all customers except for those customers participating in the California Alternate Rates for Energy or Family Electric Rate Assistance programs pursuant to Section 850.1(i).

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART JF Sheet 2
WILDFIRE HARDENING FIXED RECOVERY CHARGE (WHFRC)

JF. WILDFIRE HARDENING FIXED RECOVERY CHARGE (WHFRC) (Cont'd)

3. ISSUANCE ADVICE LETTER:

PG&E shall submit an Issuance Advice Letter no later than one day after the Wildfire Hardening Recovery Bonds or Wildfire Rate Relief Bonds are priced. The Issuance Advice Letter will include the final issuance details and a request that the Wildfire Hardening Fixed Recovery Charge be set based on the actual amount, price, and other terms of the Wildfire Hardening Recovery Bonds or, in the case of the issuance of Wildfire Rate Relief Bonds, final issuance details and a request that the subcomponent Wildfire Rate Relief Fixed Recovery Charge be set based on the actual amount, price, and other terms of the Wildfire Rate Relief Bonds. Unless before noon on the fourth business day after pricing the Commission issues an order finding that the proposed issuance does not comply with the Financing Order, the Issuance Advice Letter and the Wildfire Hardening Fixed Recovery Charges or subcomponent Wildfire Rate Relief Fixed Recovery Charges established by an Issuance Advice Letter will be effective automatically at noon on the fourth business day after pricing - and the ~~Wildfire Hardening~~ Recovery Property, established pursuant to Section 850.1(h) and the Financing Order, will come into being simultaneous with the sale of the ~~Wildfire Hardening~~ Recovery Property to the SPE.

4. WILDFIRE HARDENING FIXED RECOVERY CHARGE ADJUSTMENTS:

PG&E will submit a Routine True-Up Mechanism Advice Letter at least annually, or more often if necessary, as described in the Financing Order to adjust the Wildfire Hardening Fixed Recovery Charge to ensure timely recovery of Wildfire Hardening Recovery Bond principal, interest, and other Financing Costs or to adjust the subcomponent Wildfire Rate Relief Fixed Recovery Charge to ensure timely recovery of Wildfire Rate Relief Recovery Bond principal, interest, and other Financing Costs. All true-up adjustments to the Wildfire Hardening Fixed Recovery Charges or subcomponent Wildfire Rate Relief Fixed Recovery Charges shall ensure that the Wildfire Hardening Fixed Recovery Charges or Wildfire Rate Relief Fixed Recovery Charges generate sufficient revenues to timely pay all scheduled (or legally due) payments of principal (including, if any, prior scheduled but unpaid principal payments), interest, and other Wildfire Hardening Recovery costs to be paid with Wildfire Hardening Fixed Recovery Charge or its subcomponent Wildfire Rate Relief Fixed Recovery Charge revenues. The adjustment will be based on the following: (1) the most recent test-year sales; (2) the most recent adopted revenue allocation factors, (3) the test-year projected amortization schedule; (4) estimated ongoing financing costs; (5) an adjustment to reflect collections from the prior period; and (6) changes to projected uncollectibles. The advice letter will adjust the Wildfire Hardening Fixed Recovery Charge for each series of Wildfire Hardening Recovery Bonds issued, or will adjust the subcomponent Wildfire Rate Relief Fixed Recovery Charge for each series of Wildfire Rate Relief Bonds issued, and in both instances become effective on 1) March 1, in the case of an annual Routine True-Up, 2) September 1, in the case of a semi-annual Routine True-Up and 3) the first day of the month after the filing of an interim Routine True-Up.

In addition to the Routine True-Up Mechanism, PG&E may also make changes to the Wildfire Hardening Fixed Recovery Charge or subcomponent Wildfire Rate Relief Fixed Recovery Charge based on changes to the logic, structure, and components of the cash flow model not specified above. In this case, PG&E will file a Non-Routine True-Up Mechanism Advice Letter at least 90 days before the date when the proposed changes would become effective.

(Continued)

ELECTRIC PRELIMINARY STATEMENT PART JF Sheet 3
WILDFIRE HARDENING FIXED RECOVERY CHARGE (WHFRC)

JF. WILDFIRE HARDENING FIXED RECOVERY CHARGE (WHFRC) (Cont'd)

5. WILDFIRE HARDENING FIXED RECOVERY CHARGE:

WILDFIRE HARDENING RECOVERY BONDS Series 1 (FO Issued 6/24/21)

Rate Group	Rate ($/kWh)	
Residential	$0.00114	(I)
Small L&P/BEV1	$0.00118	(I)
A-10S/B-10S	$0.00097	(I)
A-10P/B-10P	$0.00089	(I)
A-10T/B-10T	$0.00066	(I)
E-19S/B-19S/BEV2S	$0.00083	(I)
E-19P/B-19P/BEV2P	$0.00075	(I)
E-19T/B-19T/BEV2T	$0.00066	(I)
Streetlight	$0.00100	(I)
Standby S - STOUS/SBS	$0.00118	(I)
Standby P - STOUP/SBP	$0.00231	(I)
Standby T - STOUT/SBT	$0.00059	(I)
Agriculture	$0.00104	(I)
E-20S/B-20S	$0.00076	(I)
E-20P/B-20P	$0.00069	(I)
E-20T/B-20T	$0.00045	(I)

WILDFIRE HARDENING RECOVERY BONDS Series 2 (FO Issued 8/5/22)

Rate Group	Rate ($/kWh)	
Residential	$0.00093	(R)
Small L&P/BEV1	$0.00097	(R)
A-10S/B-10S	$0.00082	(R)
A-10P/B-10P	$0.00075	(R)
A-10T/B-10T	$0.00057	(R)
E-19S/B-19S/BEV2S	$0.00069	(R)
E-19P/B-19P/BEV2P	$0.00065	(R)
E-19T/B-19T/BEV2T	$0.00056	(R)
Streetlight	$0.00082	(R)
Standby S - STOUS/SBS	$0.00103	(R)
Standby P - STOUP/SBP	$0.00175	(R)
Standby T - STOUT/SBT	$0.00052	(R)
Agriculture	$0.00096	(R)
E-20S/B-20S	$0.00060	(R)
E-20P/B-20P	$0.00058	(R)
E-20T/B-20T	$0.00039	(R)

ELECTRIC PRELIMINARY STATEMENT PART JF Sheet 3
WILDFIRE HARDENING FIXED RECOVERY CHARGE (WHFRC)

WILDFIRE HARDENING RECOVERY BONDS Series 3 (FO Issued 2/16/24)

Rate Group	Rate ($/kWh)
Residential	$X.XXXXX
Small L&P/BEV1	$X.XXXXX
A-10S/B-10S	$X.XXXXX
A-10P/B-10P	$X.XXXXX
A-10T/B-10T	$X.XXXXX
E-19S/B-19S/BEV2S	$X.XXXXX
E-19P/B-19P/BEV2P	$X.XXXXX
E-19T/B-19T/BEV2T	$X.XXXXX
Streetlight	$X.XXXXX
Standby S - STOUS/SBS	$X.XXXXX
Standby P - STOUP/SBP	$X.XXXXX
Standby T - STOUT/SBT	$X.XXXXX
Agriculture	$X.XXXXX
E-20S/B-20S	$X.XXXXX
E-20P/B-20P	$X.XXXXX
E-20T/B-20T	$X.XXXXX

WILDFIRE RATE RELIEF BONDS Series 1 (FO Issued xx/xx/xx)

Rate Group	Rate ($/kWh)
Residential	$X.XXXXX
Small L&P/BEV1	$X.XXXXX
A-10S/B-10S	$X.XXXXX
A-10P/B-10P	$X.XXXXX
A-10T/B-10T	$X.XXXXX
E-19S/B-19S/BEV2S	$X.XXXXX
E-19P/B-19P/BEV2P	$X.XXXXX
E-19T/B-19T/BEV2T	$X.XXXXX
Streetlight	$X.XXXXX
Standby S - STOUS/SBS	$X.XXXXX
Standby P - STOUP/SBP	$X.XXXXX
Standby T - STOUT/SBT	$X.XXXXX
Agriculture	$X.XXXXX
E-20S/B-20S	$X.XXXXX
E-20P/B-20P	$X.XXXXX
E-20T/B-20T	$X.XXXXX

JG. WILDFIRE HARDENING FIXED RECOVERY CHARGE BALANCING ACCOUNT (WH~~B~~FRCBA)

1. PURPOSE:

   The purpose of the WHFRCBA is to record the costs and benefits associated with Wildfire Hardening Recovery Bonds and the Wildfire Rate Relief Bonds that are not recovered from customers through the Wildfire Hardening Fixed Recovery Charge (WHFRC) or the Wildfire Rate Relief Fixed Recovery Charge (WRRFRC), a subcomponent of the WHFRC, to charge those costs to or return those benefits to customers. Wildfire Hardening Recovery Bonds and Wildfire Rate Relief Bonds are authorized by the Commission in ~~a~~ Financing Orders (FO), Decision (D.) 21-06-030, D.22-08-004; D.24-02-011; and D.24-XX-XXX, to recover costs and expenses related to catastrophic wildfires and financing costs associated with the Wildfire Hardening Recovery Bonds and Wildfire Rate Relief Bonds.

2. REVISION DATE:

   Disposition of the amounts in the account shall be determined in the Annual Electric True-Up Advice Letter, or as authorized by the Commission. Any balance in the account shall be transferred to the Distribution Revenue Adjustment Mechanism (DRAM).

3. WHFRCBA Rates:

   The WHFRCBA does not have a rate component.

4. TIME PERIOD:

   The WHFRCBA will become effective with the issuance of the first Wildfire Hardening Recovery Bonds and will expire after the Wildfire Hardening Recovery Bonds and the Wildfire Rate Relief Bonds are fully repaid and any remaining balance is returned to or recovered from customers.

5. ACCOUNTING PROCEDURES: PG&E shall maintain the WHBFRCBA by making entries at the end of each month as follows:

   a. A debit entry equal to federal income and state franchise tax accruals on revenues received to fund the Wildfire Hardening Recovery Bond and Wildfire Rate Relief Bond repayment.

   b. A credit or debit entry, as necessary, to record the flow-through or flow-back of the benefit of repairs tax deductions associated with the assets financed with the Wildfire Hardening Recovery Bonds.

   c. A credit or debit entry, as necessary, to record the interest on accumulated deferred income tax associated with the federal or State of California income or franchise taxes related to the assets financed with the Wildfire Hardening Recovery Bonds and Wildfire Rate Relief Bonds.

   d. A debit entry equal to the estimated Revenue Fees requirements on the WHFRC and the WRRFRC revenues received from customers.

   e. A credit entry equal to the servicing and administration fees paid to PG&E in excess of PG&E's recorded incremental cost of billing and collecting the Wildfire Hardening Fixed Recovery Charges and Wildfire Rate Relief Fixed Recovery Charges as specified in Preliminary Statement Part JF or acting as administrator of the special purpose entity that issues the Wildfire Hardening Recovery Bonds and the Wildfire Rate Relief Bonds.

(Continued)

5. ACCOUNTING PROCEDURES (Cont'd)

   f. An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release H.15 or its successor.

   g. A debit or credit entry, as applicable, to transfer the balance in the account to DRAM in conjunction with the Annual Electric True-Up filing or through another advice letter as approved by the Commission.

6. DEPARTING LOAD CONSUMERS:

   For information purposes, the rates in the table below will be used to credit or recover WHFRCBA balances from departing load consumers (DL Consumers), as defined in the FO(s) and the applicable Departing Load Tariffs, for each series of Wildfire Hardening Recovery Bonds and Wildfire Rate Relief Bonds. For consumers that are not DL Consumers, the WHFRCBA balances will be credited or recovered in rates in the same manner as other distribution charges and will not be collected on a volumetric basis on certain rate schedules.

   WILDFIRE HARDENING RECOVERY BONDS Series 1 (FO Issued 6/24/21)

Rate Group	**Rate ($/kWh)**
Residential	$0.00000
Small L&P/BEV1	$0.00000
A-10S/B-10S	$0.00000
A-10P/B-10P	$0.00000
A-10T/B-10T	$0.00000
E-19S/B-19S/BEV2S	$0.00000
E-19P/B-19P/BEV2P	$0.00000
E-19T/B-19T/BEV2T	$0.00000
Streetlight	$0.00000
Standby S - STOUS/SBS	$0.00000
Standby P - STOUP/SBP	($0.00001)
Standby T - STOUT/SBT	$0.00000
Agriculture	$0.00000
E-20S/B-20S	$0.00000
E-20P/B-20P	$0.00000
E-20T/B-20T	$0.00000

6. DEPARTING LOAD CONSUMERS (Cont'd):

WILDFIRE HARDENING RECOVERY BONDS Series 2 (FO Issued 8/5/22)

Rate Group	Rate ($/kWh)
Residential	($0.00023)
Small L&P/BEV1	($0.00024)
A-10S/B-10S	($0.00020)
A-10P/B-10P	($0.00019)
A-10T/B-10T	($0.00014)
E-19S/B-19S/BEV2S	($0.00017)
E-19P/B-19P/BEV2P	($0.00016)
E-19T/B-19T/BEV2T	($0.00014)
Streetlight	($0.00020)
Standby S - STOUS/SBS	($0.00026)
Standby P - STOUP/SBP	($0.00043)
Standby T - STOUT/SBT	($0.00013)
Agriculture	($0.00024)
E-20S/B-20S	($0.00015)
E-20P/B-20P	($0.00014)
E-20T/B-20T	($0.00010)

WILDFIRE HARDENING RECOVERY BONDS Series 3 (FO Issued 2/16/24)

Rate Group	Rate ($/kWh)
Residential	($X.XXXXX)
Small L&P/BEV1	($X.XXXXX)
A-10S/B-10S	($X.XXXXX)
A-10P/B-10P	($X.XXXXX)
A-10T/B-10T	($X.XXXXX)
E-19S/B-19S/BEV2S	($X.XXXXX)
E-19P/B-19P/BEV2P	($X.XXXXX)
E-19T/B-19T/BEV2T	($X.XXXXX)
Streetlight	($X.XXXXX)
Standby S - STOUS/SBS	($X.XXXXX)
Standby P - STOUP/SBP	($X.XXXXX)
Standby T - STOUT/SBT	($X.XXXXX)
Agriculture	($X.XXXXX)
E-20S/B-20S	($X.XXXXX)
E-20P/B-20P	($X.XXXXX)
E-20T/B-20T	($X.XXXXX)

(Continued)

WILDFIRE RATE RELIEF BONDS Series 1 (FO Issued x/xx/xx)

Rate Group	Rate ($/kWh)
Residential	($X.XXXXX)
Small L&P/BEV1	($X.XXXXX)
A-10S/B-10S	($X.XXXXX)
A-10P/B-10P	($X.XXXXX)
A-10T/B-10T	($X.XXXXX)
E-19S/B-19S/BEV2S	($X.XXXXX)
E-19P/B-19P/BEV2P	($X.XXXXX)
E-19T/B-19T/BEV2T	($X.XXXXX)
Streetlight	($X.XXXXX)
Standby S - STOUS/SBS	($X.XXXXX)
Standby P - STOUP/SBP	($X.XXXXX)
Standby T - STOUT/SBT	($X.XXXXX)
Agriculture	($X.XXXXX)
E-20S/B-20S	($X.XXXXX)
E-20P/B-20P	($X.XXXXX)
E-20T/B-20T	($X.XXXXX)

(Continued)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

RATE PROPOSAL

WITNESS: BENJAMIN KOLNOWSKI

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
RATE PROPOSAL
WITNESS: BENJAMIN KOLNOWSKI

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
RATE PROPOSAL
WITNESS: BENJAMIN KOLNOWSKI

A. Introduction

This chapter presents Pacific Gas and Electric Company's (PG&E) rate proposal concerning the Wildfire Rate Relief Fixed Recovery Charge (WRRFRC), shown as a subcomponent of the existing Wildfire Hardening Fixed Recovery Charge (WHFRC) rate component, and Wildfire Hardening Fixed Recovery Charge Balancing Account (WHFRCBA) for the issuance of Wildfire Rate Relief Bonds. PG&E proposes to utilize the same rate design previously presented to and approved by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 21-06-030, D.22-08-004, and D.24-02-011 to calculate the WRRFRC. The revenue requirements for the WRRFRC and WHFRCBA are provided in Attachment C to Chapter 3, Transaction Overview (M. Klemann), and are the basis for determining the illustrative WRRFRC and WHFRCBA rates presented in Attachment A of this chapter.[1]

In Section B of this chapter, PG&E presents the revenue allocation and rate design associated with the WRRFRC, WHFRCBA, and related rate changes. Section C describes how the WRRFRC would be shown on customer bills as a subcomponent of the WHFRC. Section D addresses PG&E's expectations concerning implementation of the WRRFRC and WHFRCBA. Finally, Section E is the conclusion to this chapter.

B. Rate Calculation

The WRRFRC for each customer would be equal to the product of the WRRFRC rate and the eligible sales. The design and application of the WRRFRC rate and related rate changes is provided in this section. The WRRFRC rate design proposed in this application is consistent with the rate design adopted by D.21-06-030, D.22-08-004, and D.24-02-011.

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1 As described in Chapter 3, Attachment C sets forth the anticipated revenue requirement based on the Authorized Amount.

1. Applicability

Section 850.1(a)(2), which was passed as part of Assembly Bill (AB) 1054, provides that the WRRFRC and related Fixed Recovery Tax Amounts (FRTA), accrued in the WHFRCBA, are to be recovered from existing and future customers in PG&E's service territory until Wildfire Rate Relief Bonds and associated financing costs are paid in full by the financing entity. Section 850.1(i) further specifies that the WRRFRC and FRTA shall not be imposed on customers that receive either the California Alternate Rates for Energy (CARE) or the Family Electric Rate Assistance (FERA) discount pursuant to Section 739.1. Accordingly, all Direct Access, Community Choice Aggregation, and bundled service customers would pay the WRRFRC and charges associated with the WHFRCBA, unless they are participating in the CARE or FERA programs.

2. Non-Bypassability

Sections 850.1(b) and (i) provide that the WRRFRC and FRTA costs accrued in the WHFRCBA are non-bypassable and recoverable from all existing and future customers in PG&E's service territory except for those participating in CARE or FERA programs. Under Sections 850(a)(3) and (a)(13), customers in PG&E's service territory include any consumer of electricity transmitted or distributed by means of electric transmission or distribution facilities in the geographical area that PG&E provides with electric distribution service.

In connection with the first issuance of Wildfire Hardening Recovery Bonds authorized by D.21-06-030, the Commission approved revisions to PG&E's departing load (DL) tariffs to add language effectuating the non-bypassability of the WHFRC and WHFRCBA to customers.[2] Under these tariffs, customers remain subject to the WHFRC and WHFRCBA as DL customers, if they either (1) no longer take transmission and distribution retail service from PG&E after the date of the Financing Order, or (2) meet relevant criteria to be a departing load customer in the applicable tariffs after the date of the Financing Order. PG&E proposes that the same DL tariffs

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[2] Advice Letter (AL) 6448-E proposed revisions to PG&E Electric Schedules E-DCG, E-NMDL, E-TMDL, E-SDL, and E-NWDL and was accepted effective January 29, 2022.

will apply without modification to customers for the Wildfire Rate Relief Bonds.[3]

Consistent with the first, second, and expected third issuances of Wildfire Hardening Recovery Bonds, for DL customers, PG&E proposes to calculate the WRRFRC and WHFRCBA related amounts that would need to be paid using an approach that is consistent with the method currently in place for calculation of DL charges under existing tariffs. For example, new municipal DL customers that depart after the date of the Financing Order would pay the WRRFRC and WHFRCBA based on: (a) the last 12 months of the customer's recorded pre-departure use; (b) actual use; or (c) another method authorized under the existing tariffs.

3. Revenue Allocation

The costs PG&E proposes to finance through securitization are vegetation management costs adopted in its 2023 General Rate Case (GRC). These costs, which have been determined to be just and reasonable for recovery in rates, are necessary to provide safe and reliable distribution service.[4] Additionally, these costs are associated with wildfire mitigation and qualify for the special allocation of wildfire mitigation costs set forth in the revenue allocation settlement (RA Settlement Agreement) adopted by the Commission in D.21-11-016 in PG&E's 2020 GRC Phase II proceeding Application ((A.) 19-11-019).[5] Consistent with the revenue allocation methodology approved by D.21-06-030, D.22-08-004, and D.24-02-011, for PG&E's Initial, Second, and Third AB 1054 Securitizations

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[3] PG&E reserves the right to propose a different definition of DL consumers in future applications for securitization under Sections 850 *et seq*.

[4] See Chapter 1, Introduction (M. Becker), at 1-5 to 1-12.

[5] See A.19-11-019, Motion of PG&E for Adoption of Revenue Allocation Supplemental Settlement Agreement (with attached Supplemental Settlement Agreement in PG&E's GRC Phase II (A.19-11-019) on Revenue Allocation Issues), filed April 8, 2021 ("RA Settlement Motion")). The parties to the RA Settlement Agreement were PG&E, Public Advocates Office at the California Public Utilities Commission, The Utility Reform Network, Energy Producers and Users Coalition, the California Large Energy Consumers Association, the California Farm Bureau Federation, the Agricultural Energy Consumers' Association, the Direct Access Customer Coalition, the Energy Users Forum, the Small Business Utility Advocates, the California City and County Street Light Association, the California Manufacturers & Technology Association, and the Federal Executive Agencies (collectively, the "RA Settling Parties").

respectively, PG&E proposes to apply the same allocation methodology outlined in the RA Settlement Agreement to the WRRFRC and WHFRCBA for the Wildfire Rate Relief Bonds.

Under the relevant portion of the RA Settlement Agreement, there is a specific allocation methodology for the combined revenue requirement associated with wildfire mitigation costs, including “Wildfire Mitigation costs that are securitized and recovered through bonds (as provided by AB 1054).”[6] Under this revenue allocation methodology, a two-step process is applied to determine a weighted average of distribution allocation factors and equal percent of total revenue (EPT) factors to allocate the combined revenue requirement associated with wildfire mitigation costs among customer groups.

Based on the application of the allocation methodology and formulas as set forth in the RA Settlement Agreement, the illustrative rates presented in Attachment A reflect an example allocation for the WRRFRC and WHFRCBA using a weighting of 19.6 percent distribution and 80.4 percent EPT. This weighting is based on the qualifying combined wildfire mitigation revenue requirement in rates as of PG&E’s 2024 Annual Electric True-Up (AET), effective January 1, 2024.[7] Upon issuance of Wildfire Rate Relief Bonds authorized by this application, PG&E will calculate the weighted allocation based on the combined wildfire mitigation revenue requirement approved to be in rates at that time and utilize the distribution and EPT allocation factors also in effect at that time. Consistent with the approach adopted by the Commission in D.21-06-030, D.22-08-004, and D.24-02-011, PG&E proposes that once the allocation methodology for the bonds is set at the time of issuance, it will remain the same for the life of the bonds, with adjustments for sales changes to collect the revenue requirement. PG&E proposes that the WRRFRC be collected on a volumetric basis (per

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6 A.19-11-019, RA Settlement Motion, Attachment 1 at 9 (defining Wildfire Mitigation costs to include revenue requirements associated with specific memorandum accounts and balancing accounts, other revenue requirements directly related to wildfire mitigation, and wildfire mitigation costs securitized and recovered through bonds such as the Wildfire Hardening Recovery Bonds).

7 See Table 5 of AL 7116-E.

kilowatt-hour (kWh)) by class and voltage consistent with D.21-06-030, D.22-08-004, and D.24-02-011.[8]

4. Rate Design

As described above, customers participating in the CARE and FERA programs are exempt from this charge. Consistent with D.21-06-030, D.22-08-004, and D.24-02-011, PG&E proposes that the WRRFRC charge (and distribution charges for the WHFRCBA) be increased by an equal cents per kWh adder for customers not participating in CARE and FERA to provide the source of funding for these exemptions.[9]

As a general matter, the total rates for most customer classes are developed by adding the rates for each component together to derive the total applicable rate, so total rates would increase by the amount of the WRRFRC.[10] However, residential rates are governed by the rate design rules established in D.15-07-001 and would not change by a uniform amount in all rate tiers. In addition, the application of the CARE and FERA exemptions, and the funding of the CARE and FERA discounts, are impacted by implementation of the WRRFRC. Accordingly, PG&E's proposal also includes a description of these changes as described further below.

PG&E has provided an illustration of the revenue allocation and rate design impact of the WRRFRC and WHFRCBA for the total Authorized Amount. This illustration, provided as Attachment A, shows full

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8 In addition to the WRRFRC, costs will be accumulated in the WHFRCBA. As described in Chapter 6, Ratemaking Mechanisms (S. Sims), amounts accrued in this account will be transferred to the Distribution Revenue Adjustment Mechanism account for recovery in distribution rates each year in the AET Advice Letter. PG&E proposes to treat these costs like the WRRFRC for purposes of revenue allocation, but to design the rates in the same manner as other distribution charges which may not be volumetric (per kWh). Accordingly, CARE and FERA customers are exempt. The WHFRCBA charges will be combined with other distribution charges on bills of non-exempt customers.

9 D.21-06-030 at 33; D.24-02-11 at 35. See also D.20-11-007 at 81; D.22-08-004 at 78; D.23-02-023 at 73-75 (Southern California Edison third AB 1054 securitization).

10 An exception to this rule is made for Schedules B-19 and B-20. As adopted by D.23-11-005, Schedule B-19 and B-20 distribution rates are adjusted on a revenue neutral basis to effectuate recovery of WHFRC revenues through customer and demand charges, rather than through energy charges. This treatment would apply to WRRFRC revenues which are recovered through the WHFRC rate component.

implementation of the WRRFRC, as a subcomponent of the WHFRC. Full implementation of the new WRRFRC rate also impacts Public Purpose Program rates and distribution rates, including the Conservation Incentive Adjustment (CIA) and the charge for the WHFRCBA. PG&E's illustrative annual revenue requirement for the WRRFRC and WHFRCBA from Attachment C to Chapter 3, Transaction Overview (M. Klemann), is $319.0 million.[11] The illustrative rates presented in Attachment A are calculated using PG&E's adopted 2024 sales forecast and the rate design methodology effective in rates at the time of filing this application. PG&E's 2024 forecast of eligible sales is 70,203 gigawatt-hours, which excludes exempt CARE and FERA sales. As discussed above, the WRRFRC rate varies by class and voltage, but the illustrative initial average WRRFRC rate alone, for applicable customers, is estimated to be $0.00451 per kWh.

a. Residential Rate Design

Residential rates are first determined on a total basis. D.15-07-001, and subsequently modified by D.21-03-003 and D.21-11-016, establishes the relationship between the total rates for those residential rates that continue to have a tiered rate structure (e.g., Schedule E-1). Once the total rates are determined based on the relationships prescribed by these decisions,[12] rates are unbundled into their component pieces, where the CIA is set residually to provide the adopted rate differentials by rate tier. PG&E proposes to retain the current rate relationships by tier with the addition of the WRRFRC. As a result, total rates would not change by the same cents per kWh amount in all tiers.

1) CARE Rate Design

As discussed in the Applicability section above (B.1), CARE customers are exempt from the WRRFRC and the WHFRCBA. Section 739.1(c)(1) provides that the average CARE discount must

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[11] The WRRFRC revenue requirement is $316.6 million and the WHFRCBA revenue requirement is $2.4 million.

[12] For example, the total tier 2 rate is established as ratio to the total tier 1 rate, where that ratio is equal to 1.25 to 1.0. See D.15-07-001 at 277-278.

be between 30 and 35 percent.[13] PG&E proposes to retain these rate exemptions for CARE customers.

On June 30, 2022, AB 205 was enacted. Among other items, AB 205 amended language in § 739.1(c) related to the determination of the average effective CARE discount. AB 205 does not directly impact implementation of the WRRFRC because customers enrolled in the CARE program are exempt from the WRRFRC pursuant to Section 850.1(i) as described above. However, AB 205 does alter how total rates for residential customers are designed with respect to rate exemptions for CARE customers. More specifically, AB 205 modified the calculation of the average effective discount in order to exclude charges for which CARE customers are exempted, discounts to fixed charges, and other rates paid by non-CARE customers.

Pursuant to the Scoping Memo issued on November 2, 2022, in Rulemaking (R.) 22-07-005, the *Rulemaking to Advance Demand Flexibility Through Electric Rates* (Demand Flex Order Instituting Rulemaking (OIR)), the Commission addressed the broader issue of how the average effective CARE discount is impacted by AB 205, in relation to other charges including the WHFRC.[14]

On May 9, 2024, the Commission issued D.24-05-028 in the Demand Flex OIR. This decision adopted the following methodology to calculate and apply CARE discounts to be effective January 1, 2025 upon submittal of a Tier 1 advice letter.[15]

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13 PG&E's average CARE discount is currently 35.0 percent.

14 See R.22-07-005, Assigned Commissioner's Phase 1 Scoping Memo and Ruling (Nov. 2, 2022), at 3-4 (identifying as issue for Phase 1, Track A: "How should the Commission implement the requirements of AB 205 to adjust the average effective discount for CARE so that it does not reflect any charges for which CARE customers are exempted, discounts to fixed charges or other rates paid by non-CARE customers, or bill savings resulting from participation in other programs?").

15 See D.24-05-028, Decision Addressing Assembly Bill 205 Requirements for Electric Utilities, pp. 28-29.

a) *First, calculate the total revenues for CARE customers that would have been produced for the same billed usage by non-CARE customers;*

b) *Second, remove from the total revenues all of the charges that CARE customers are exempted from and all rate and charge discounts that CARE customers receive; excluding discounts on income-graduated fixed charges;*

c) *Third, apply the applicable CARE discount rate to the volumetric and fixed components of the rate;*

d) *Fourth, apply any remaining discount to CARE customers' fixed charge that is needed to achieve the required income-graduated fixed charge for CARE customers; and*

e) *Finally, allocate the CARE discount budget for collection on an equal cents per kWh basis.*

This new methodology adopted by D.24-05-028 is not currently effective in rates and therefore is not reflected in the illustrative rates presented in Attachment A. However, PG&E expects this methodology to be in effect prior to issuing the Wildfire Rate Relief Bonds in 2025. Upon implementing the WRRFRC, PG&E will calculate total rates incorporating the approved methodology for the CARE effective discount at that time.

2) FERA Rate Design

As discussed in the Applicability section above (B.1), FERA customers are also exempt from the WRRFRC and the WHFRCBA. Section 739.12 requires that the FERA discount be set to 18 percent.

PG&E proposes to retain this rate exemption for FERA customers and apply rate design consistent with PG&E's proposal adopted by the Commission in D.21-06-030.[16] Therefore,

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16 See D.21-06-030 at 83 (concluding that "the treatment of CARE/FERA Customers shall be as proposed by PG&E.").

residential rates for FERA customers will be adjusted as necessary to retain the prescribed FERA discount at 18 percent.[17]

Consistent with the exemption treatment for the first, second, and third issuances of the Wildfire Hardening Recovery Bonds for FERA customers, the exemptions to the WRRFRC and WHFRCBA will be identified as part of the prescribed discount in the same way FERA customers are exempted from paying the Wildfire Fund Charge (WFC). Specifically, with these exemptions, the FERA discount is made up of exemptions to the WFC, the WRRFRC, and WHFRCBA exemptions, the Recovery Bond Charge and Recovery Bond Credit exemptions, and a residual distribution/CIA discount as is necessary to maintain the 18 percent discount. This treatment is consistent with the treatment to effectuate the 35 percent average effective discount for CARE customers prior to the changes ordered by AB 205 as described in the section above.

C. Rate Credit Associated With Issuance of the Wildfire Rate Relief Bonds

As described in Chapter 6, Ratemaking Mechanisms (S. Sims), upon issuance of the Wildfire Rate Relief Bonds, PG&E will credit the Distribution Revenue Adjustment Mechanism (DRAM) for actual incurred vegetation management expenses financed using Wildfire Rate Relief Bonds. PG&E proposes to provide this credit to customers by reducing distribution rates over a 12-month period in the next consolidated rate change following the bond issuance.[18] PG&E also proposes to allocate this distribution revenue requirement reduction to customer classes by applying the special allocation of wildfire mitigation costs as determined in the 2020 GRC Phase 2 RA settlement which would be consistent with the allocation methodology used for the WRRFRC.

All else equal, based on the projected bond issuance of $2.356 billion in authorized vegetation management expenses as presented in Table 1-3 of

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17 Like the WHFRC, FERA customers will be exempt from amounts assessed for the WHFRCBA, and CARE and FERA bills will increase (or decrease) as necessary to retain the prescribed FERA discounts.

18 Providing the rate reduction through distribution rates is in the same manner as the revenues were originally collected from customers.

Chapter 1, PG&E anticipates that the system average rate would be reduced by approximately 2.7 cents per kWh, or a reduction of 7 percent, compared to rates in effect today for a 12-month period once the bonds are issued and implemented in rates.[19] This rate reduction would lower the average non-CARE residential electric monthly bill by approximately $15.75 over this 12-month period, followed by a bill increase of approximately $2.40 for the remainder of the bond term.[20]

D. Bill Presentation

Section 850.1(g) requires PG&E to show the WRRFRC on each customer's electric bill. Consistent with the bill presentation approved by D.21-06-030 for the First AB 1054 Securitization and continued for the Second and Third AB 1054 Securitizations, PG&E proposes to show the WRRFRC in the unbundled charge section on page 2 of the bill. If the description does not appear on page 2 of each Customer's bill, then the description shall be accessible via a uniform resource locator address on the bill to a PG&E website that includes further information on the definitions used on the bill, and PG&E shall also include the descriptions in an annual bill insert. The WRRFRC, appearing as a subcomponent of the existing WHFRC, would be included as part of the "Wildfire Hardening Charge" on the bill and would be presented as a single line item for billing and accounting purposes. For applicable customers, this single line item would combine together the rate values for the Initial AB 1054 Securitization, Second AB 1054 Securitization, Third AB 1054 Securitization, and the rate resulting from the WRRFRC for the Wildfire Rate Relief Bonds proposed in this application. An example of the unbundled charges (for a residential tiered rate) is shown in Table 7-1 below based on the total revenue requirement. As discussed above, the WRRFRC will not apply to CARE and FERA customers and therefore would not appear on the bills for those customers.

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19 This rate reduction includes the net impact of the distribution rate reduction resulting from the credit to DRAM and the implementation of the WRRFRC/WHFRCBA.

20 The average residential bill impact is based on a customer using an average of 500 kWh per month.

TABLE 7-1
BILL PRESENTATION FOR THE WRRFRC WITH ELECTRIC CHARGES

Line No.	Your Electric Charges Breakdown	Amount
1	Conservation Incentive	$1.12
2	Generation	88.44
3	Transmission	23.58
4	Distribution	105.81
5	Electric Public Purpose Programs	13.07
6	Nuclear Decommissioning	(1.30)
7	Wildfire Fund Charge	2.81
8	Competition Transition Charges	0.51
9	Energy Cost Recovery Amount	(0.02)
10	Recovery Bond Charge	2.99
11	Recovery Bond Credit	(2.99)
12	Wildfire Hardening Charge[(a)]	3.62
13	Taxes and Other	0.15
14	Total Electric Charges	$237.79

(a) As noted above, the Wildfire Hardening Charge line item would combine the WHFRC rate from the Initial AB 1054 Securitization, Second AB 1054 Securitization, and Third AB 1054 Securitization, together with the WRRFRC rate proposed for the Wildfire Rate Relief Bonds.

Consistent with D.21-06-030, D.22-08-004, and D.24-02-011,[21] the following description of the Wildfire Hardening Charge will be included on the definition page of PG&E's energy statement. This definition was implemented concurrent with the rate implementation on December 1, 2021 for the first issuance of Wildfire Hardening Recovery Bonds and has been modified to reflect the Wildfire Rate Relief Charge.

- Wildfire Hardening Charge: PG&E has been permitted to issue bonds that enable it to recover more quickly certain costs related to preventing and mitigating catastrophic wildfires, while reducing the total cost to its customers. Your bill for electric service includes fixed recovery charges called the Wildfire Hardening Charge, which includes the Wildfire Rate Relief Charge, that have been approved by the CPUC to repay those bonds. The right to recover these charges has been transferred to a separate entity (called the Special Purpose Entity) that issued the bonds and does not belong to PG&E. PG&E is collecting these fixed recovery charges on behalf

[21] D.21-06-030 at 70-71 and 124-125 (Ordering Paragraph (OP) 30); D.22-08-004 at 119-20 (OP 30); D. 24-02-011 at 122-23 (OP 30).

of the Special Purpose Entity. For details visit: www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_JF.pdf.

E. Implementation

The WRRFRC authorized by the Financing Order will appear on bills as part of the Wildfire Hardening Charge as soon as practicable following issuance of the Wildfire Rate Relief Bonds, but in all events no later than necessary to bill and collect funds sufficient to pay principal, interest and other Ongoing Financing Costs payable on the first payment date of the issuance of Wildfire Rate Relief Bonds authorized by this application. If the Commission adopts an alternative approach to implement the WRRFRC, more time and resources may be required to implement the billing system changes, potentially resulting in delays to already approved rate change projects.

F. Conclusion

PG&E requests that the Commission approve PG&E's rate proposal concerning the WRRFRC, WHFRCBA, and related changes, as described above, for the Wildfire Rate Relief Bonds.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

ATTACHMENT A

AVERAGE PRESENT RATES AND

PROPOSED ILLUSTRATIVE RATES

Pacific Gas and Electric Company
Chapter 7 Attachment A
Average Present and Proposed Illustrative Rates
Rate Changes for the Wildfire Rate Relief (WRRFRC) and Related Changes
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	Illustrative Rate Change (cents per kWh) (Year 1)			
	6/1/2024 Average Present Rates	Proposed Average Rate	Average Rate Change	Percent Change
Customer Class	**Bundled Service**			
Residential	38.42	35.76	-2.66	-6.9%
CARE	28.79	26.76	-2.03	-7.0%
Non-CARE	45.41	42.29	-3.12	-6.9%
Small Commercial	44.79	41.47	-3.32	-7.4%
Medium Commercial	40.47	37.54	-2.93	-7.2%
A/B-10T	23.93	22.25	-1.67	-7.0%
A/B-10P	37.07	34.34	-2.73	-7.4%
A/B-10S	40.54	37.60	-2.94	-7.2%
E/B-19	34.93	32.40	-2.53	-7.2%
E/B-19T	27.45	24.29	-3.16	-11.5%
E/B-19P	29.41	27.32	-2.09	-7.1%
E/B-19S	35.82	33.23	-2.60	-7.3%
Streetlight	48.21	44.84	-3.38	-7.0%
Standby	23.47	21.91	-1.56	-6.7%
STOU T	22.31	20.86	-1.45	-6.5%
STOU P	55.69	50.10	-5.59	-10.0%
STOU S	38.09	36.30	-1.79	-4.7%
Agriculture	40.09	37.11	-2.99	-7.4%
E/B-20	25.25	23.39	-1.86	-7.4%
E/B-20 T	21.38	19.80	-1.58	-7.4%
E/B-20 P	29.03	26.92	-2.11	-7.3%
E/B-20 S	34.17	31.48	-2.69	-7.9%
Average Bundled Rate	37.08	34.42	-2.66	-7.2%
Customer Class	**Direct Access/Community Choice Aggregation (DA/CCA)**			
Residential	24.36	21.45	-2.91	-11.9%
CARE	10.71	8.70	-2.01	-18.8%
Non-CARE	27.82	24.68	-3.13	-11.3%
Small Commercial	28.77	25.45	-3.32	-11.5%
Medium Commercial	22.75	19.90	-2.85	-12.5%
A/B-10T	12.32	10.40	-1.92	-15.6%
A/B-10P	20.09	17.57	-2.52	-12.6%
A/B-10S	22.78	19.92	-2.85	-12.5%
E/B-19	18.54	16.08	-2.46	-13.3%
E/B-19T	8.98	7.60	-1.38	-15.3%
E/B-19P	15.57	13.42	-2.14	-13.8%
E/B-19S	18.84	16.35	-2.49	-13.2%
Streetlight	29.21	25.83	-3.37	-11.6%
Standby	13.22	11.18	-2.05	-15.5%
STOU T	10.76	8.92	-1.84	-17.1%
STOU P	67.87	60.07	-7.79	-11.5%
STOU S	22.01	20.37	-1.64	-7.4%
Agriculture	23.24	20.56	-2.68	-11.5%
E/B-20	11.78	9.92	-1.86	-15.8%
E/B-20 T	7.05	5.60	-1.44	-20.5%
E/B-20 P	14.31	12.21	-2.10	-14.6%
E/B-20 S	15.82	13.63	-2.18	-13.8%
Average DA/CCA Rate	20.69	18.07	-2.62	-12.7%

* Illustrative rates are based on the 2024 test year sales forecast and currently effective rate design methodology. Upon implementation, rates will be updated based on the then current sales forecast and rate design methodology.

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Residential Rates and Bills (Schedule E-1) - Year 1

Residential Rate	Non Care Rates (cents per kWh)		
	6/1/2024	Illustrative Rate	% Change
Tier 1 (Baseline)	42.68	39.81	-6.7%
Tier 2 (101% to 400% of	53.41	49.85	-6.7%
Tier 3 (>400% of baseline)	53.41	49.85	-6.7%
Residential Rate	CARE Rates (cents per kWh)		
	6/1/2024	Illustrative Rate	% Change
Tier 1 (Baseline)	27.75	25.88	-6.7%
Tier 2 (101% to 400% of	34.72	32.41	-6.7%
Tier 3 (>400% of baseline)	34.72	32.41	-6.7%
Residential Bills	Average Monthly Non-CARE Bill with FRC		
	6/1/2024	Illustrative Bill	% Change
350 kWh	$145.94	$135.52	-7.1%
500 kWh	$226.05	$210.30	-7.0%
700 kWh	$332.86	$310.00	-6.9%
Residential Bills	Average Monthly CARE Bill		
	6/1/2024	Illustrative Bill	% Change
350 kWh	$91.66	$84.89	-7.4%
500 kWh	$143.75	$133.51	-7.1%
700 kWh	$213.19	$198.33	-7.0%

* CARE rates and bills do not include the WRRFRC, but change to retain the CARE percentage discount under current rate design methodology.

	Illustrative Rate Change (cents per kWh) Years 2-10			
	6/1/2024 Average Present Rates	Proposed Average Rate	Average Rate Change	Percent Change
Customer Class	**Bundled Service**			
Residential	38.42	38.83	0.41	1.1%
CARE	28.79	29.10	0.31	1.1%
Non-CARE	45.41	45.89	0.48	1.1%
Small Commercial	44.79	45.30	0.51	1.1%
Medium Commercial	40.47	40.91	0.44	1.1%
A/B-10T	23.93	24.19	0.26	1.1%
A/B-10P	37.07	37.47	0.40	1.1%
A/B-10S	40.54	40.98	0.44	1.1%
E/B-19	34.93	35.31	0.38	1.1%
E/B-19T	27.45	27.72	0.27	1.0%
E/B-19P	29.41	29.74	0.33	1.1%
E/B-19S	35.82	36.21	0.39	1.1%
Streetlight	48.21	48.79	0.58	1.2%
Standby	23.47	23.73	0.26	1.1%
STOU T	22.31	22.55	0.24	1.1%
STOU P	55.69	56.54	0.85	1.5%
STOU S	38.09	38.51	0.42	1.1%
Agriculture	40.09	40.54	0.45	1.1%
E/B-20	25.25	25.52	0.27	1.1%
E/B-20 T	21.38	21.60	0.22	1.1%
E/B-20 P	29.03	29.35	0.32	1.1%
E/B-20 S	34.17	34.52	0.35	1.0%
Average Bundled Rate	37.08	37.48	0.40	1.1%
Customer Class	**Direct Access/Community Choice Aggregation (DA/CCA)**			
Residential	24.36	24.81	0.45	1.8%
CARE	10.71	11.01	0.31	2.9%
Non-CARE	27.82	28.30	0.48	1.7%
Small Commercial	28.77	29.28	0.51	1.8%
Medium Commercial	22.75	23.19	0.44	1.9%
A/B-10T	12.32	12.58	0.26	2.1%
A/B-10P	20.09	20.49	0.40	2.0%
A/B-10S	22.78	23.22	0.44	1.9%
E/B-19	18.54	18.92	0.38	2.1%
E/B-19T	8.98	9.25	0.27	3.0%
E/B-19P	15.57	15.89	0.33	2.1%
E/B-19S	18.84	19.22	0.39	2.1%
Streetlight	29.21	29.79	0.58	2.0%
Standby	13.22	13.49	0.27	2.0%
STOU T	10.76	11.00	0.24	2.2%
STOU P	67.87	68.71	0.85	1.2%
STOU S	22.01	22.43	0.42	1.9%
Agriculture	23.24	23.69	0.45	1.9%
E/B-20	11.78	12.06	0.29	2.4%
E/B-20 T	7.05	7.27	0.22	3.2%
E/B-20 P	14.31	14.63	0.32	2.2%
E/B-20 S	15.82	16.16	0.35	2.2%
Average DA/CCA Rate	20.69	21.09	0.41	2.0%

* Illustrative rates are based on the 2024 test year sales forecast and currently effective rate design methodology. Upon implementation, rates will be updated based on the then current sales forecast and rate design methodology.

Pacific Gas and Electric Company
Chapter 7 Attachment A
Average Present and Proposed Illustrative Rates
Rate Changes for the Wildfire Rate Relief (WRRFRC) and Related Changes
Page 4

Residential Rates and Bills (Schedule E-1) - Years 2 - 10

Residential Rate	Non Care Rates (cents per kWh)		
	6/1/2024	Illustrative Rate	% Change
Tier 1 (Baseline)	42.68	43.11	1.0%
Tier 2 (101% to 400% of Baseline)	53.41	53.95	1.0%
Tier 3 (>400% of baseline)	53.41	53.95	1.0%
Residential Rate	CARE Rates (cents per kWh)		
	6/1/2024	Illustrative Rate	% Change
Tier 1 (Baseline)	27.75	28.03	1.0%
Tier 2 (101% to 400% of Baseline)	34.72	35.07	1.0%
Tier 3 (>400% of baseline)	34.72	35.07	1.0%
Residential Bills	Average Monthly Non-CARE Bill with FRC		
	6/1/2024	Illustrative Bill	% Change
350 kWh	$145.94	$147.52	1.1%
500 kWh	$226.05	$228.44	1.1%
700 kWh	$332.86	$336.34	1.0%
Residential Bills	Average Monthly CARE Bill		
	6/1/2024	Illustrative Bill	% Change
350 kWh	$91.66	$92.69	1.1%
500 kWh	$143.75	$145.30	1.1%
700 kWh	$213.19	$215.45	1.1%

* CARE rates and bills do not include the WRRFRC, but change to retain the CARE percentage discount under current rate design methodology.

WRRFRC and WHFRCBA Rates (cents per kWh)		
	WRRFRC Rate	WHFRCBA Rate
Customer Class		
Residential	0.364	0.003
CARE	-	-
Non-CARE	0.516	0.004
Small Commercial	0.547	0.004
Medium Commercial	0.477	0.004
A/B-10T	0.300	0.002
A/B-10P	0.437	0.003
A/B-10S	0.480	0.004
E/B-19	0.416	0.003
E/B-19T	0.305	0.002
E/B-19P	0.362	0.003
E/B-19S	0.423	0.003
Streetlight	0.580	0.004
Standby	0.297	0.002
STOU T	0.275	0.002
STOU P	0.881	0.007
STOU S	0.457	0.003
Agriculture	0.483	0.004
E/B-20	0.318	0.002
E/B-20 T	0.260	0.002
E/B-20 P	0.355	0.003
E/B-20 S	0.382	0.003
Average Rate	0.404	0.003

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARGARET BECKER

Q 1 Please state your name and business address.

A 1 My name is Margaret Becker, and my business address is Pacific Gas and Electric Company (PG&E or the Utility), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am Vice President and Treasurer at PG&E. In addition to managerial duties, I lead a team responsible for numerous aspects of PG&E's Treasury operations. These responsibilities have included financing, administration of debt obligations, investment management, cash management, accounts payable, and liquidity risk management. I also manage the Utility's rating agency and bank relationships.

Q 3 Please summarize your educational and professional background.

A 3 I joined PG&E after graduating from Harvard Business School with a Master's degree in Business Administration. I also hold a Bachelor's degree in Economics from Stanford University. During my 14 years at the Utility, I have served in multiple positions overseeing its financial activity, including serving as a Senior Manager in the Financial Forecasting and Analysis department and Assistant Treasurer for four years prior to my current role. In my current role as Treasurer, I have raised significant debt and equity capital to support utility operations.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Wildfire Rate Relief Bond:

- Chapter 1, "Introduction."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MONICA KLEMANN

Q 1 Please state your name and business address.

A 1 My name is Monica Klemann, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Assistant Treasurer in the in the Treasury organization, responsible for executing financing transactions (debt, equity, and bank credit facilities) in support of PG&E's capital and liquidity requirements, managing financial risk, ensuring compliance with all financial covenants, managing the Company's relationship with the financial community (banks, credit rating agencies, etc.), liquidity risk management, and cash management.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Accounting in 2005 from Loyola Marymount University, Los Angeles. I joined PG&E in 2010 as a Senior Financial Analyst in the Accounting Department, working on the quarterly and annual reports filed with the Securities and Exchange Commission, California Public Utilities Commission, and Federal Energy Regulatory Commission. I also worked in Investor Relations and Business Finance before joining the Treasury team in April 2016.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Wildfire Rate Relief Bond:

- Chapter 3, "Transaction Overview."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF BENJAMIN KOLNOWSKI

Q 1 Please state your name and business address.

A 1 My name is Benjamin Kolnowski, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 My current position at PG&E is Senior Manager of Electric Rates within the Regulatory Affairs organization. In this capacity, I am responsible for overseeing the development of electric rates, including rate design proposals for presentation, review, and approval by the California Public Utilities Commission.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of California, Los Angeles in June 2012. From 2012 to 2015, I worked as an Engineer in PG&E's Gas System Planning Department. In this role, my primary responsibility was to analyze the hydraulics of the gas system to support gas operations and enable customer growth. From 2015 to 2016, I joined the Strategy, Technology, and Support team at PG&E, where I developed technology, processes, and procedures to support the Gas System Planning Department. This included analyzing hourly gas meter data to understand the relationship between various weather variables and gas use, resulting in an hourly forecast by climate zone.

I received a Master's degree in Business Administration (MBA) from the Anderson School of Business at University of California, Los Angeles in June 2018. I rejoined PG&E in September 2018 as an MBA Associate, working in the Rates Department within Regulatory Affairs on rotation. In April 2019, I permanently joined the Rates Department as an Expert Data Scientist. One of my main responsibilities in both roles had been to develop the electric sales and customer forecasts used for electric rate design. In February 2020, I began managing the Electric Rates team. In July 2023, I was promoted to my current role as Senior Manager of the Electric Rates team where I support PG&E's rate design proposals in various proceedings including the Energy Resource and Recovery Account Forecast, General Rate Case, and securitization proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Wildfire Rate Relief Bond:

- Chapter 7, "Rate Proposal."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KATRINA T. NIEHAUS

Q 1 Please state your name and business address.

A 1 My name is Katrina T. Niehaus, and my business address is Goldman Sachs & Co., 200 West St, New York, NY 10282.

Q 2 Briefly describe your responsibilities at Goldman Sachs & Co.

A 2 I am currently a Managing Director, Head of the Corporate Asset Backed Securities Finance Group at Goldman. As a Managing Director, I oversee a group that has the responsibility for the origination and structuring of securitizations backed by a broad range of assets including renewable loans/leases/power purchase agreements, new infrastructure (data centers, cell towers, etc.), intellectual property, and small business loans.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from the Wharton School at the University of Pennsylvania with a Bachelor's degree in Economics. I also hold my Master's degree in Public Administration from Columbia University. During my time at Goldman, I have assisted a number of utilities and states through the securitization process as an advisor or underwriter including: Pacific Gas and Electric Company's Assembly Bill 1054 transactions, Duke Energy, Jersey Central Power & Light, AEP Texas Central, Entergy Texas, CenterPoint Energy, First Energy, Consumers Energy, The Long Island Department of Power, The State of Hawaii, and Public Service Company of New Hampshire.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Wildfire Rate Relief Bond:

- Chapter 2, "Background on Utility Securitization."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DIVYA RAMAN

Q 1 Please state your name and business address.

A 1 My name is Divya Raman, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Manager of the Economic Analysis team in the Corporate Development and Economic Analytics section of the Finance Department, where I am responsible for producing and supervising the preparation of revenue requirement models and sponsoring related testimony.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Management from Birla Institute of Technology and Science, India in 2005. I also received my Master of Science degree in Finance from London Business School in 2009.

I started my career at PG&E in 2012 as a Senior Analyst on the Capital Recovery and Analysis team and was promoted to Expert Analyst in 2013. My responsibilities included analysis and presentation of Depreciation Expense, Plant and Rate base in various rate cases. I was the Plant and Rate base, Depreciation Expense witness in PG&E's first formula rate Transmission Owner filing.

In 2018, I was promoted to Principal Analyst in the Financial Forecasting and Revenue Requirements team. My focus in this position included reviewing PG&E's revenue requirement in the 2019 Gas Transmission and Storage, 2020 General Rate Case, as well as PG&E's 2018 and 2019 Catastrophic Event Memorandum Account filings. In 2020, I was promoted to Manager of the Revenue Requirement and Regulatory Results of Operations team. In this position, I produced and supervised revenue requirement calculations for regulatory filings and served as the expert witness for revenue requirements in regulatory proceedings. In 2022 I was promoted to my current position as Manager of the Economic Analysis team.

As the Manager for the Economic Analysis team, I am responsible for leading a team of financial analysts that support strategic questions facing the company, like valuation, long-term enterprise wide financial forecasting, analytical support for regulatory proposals, cost of capital, and non-traditional funding strategies. I also support the evaluation, design, and use of various financial models and evaluation tools that the Economic Analysis team creates.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Wildfire Rate Relief Bond:

- Chapter 4, "Customer Benefits":
  - Sections A, B, C, and E.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KAMRAN RASHEED

Q 1 Please state your name and business address.

A 1 My name is Kamran Rasheed, and my business address is Pacific Gas and Electric Company (PG&E or the Utility), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Director of PG&E's Electric Vegetation Management (VM) Operations within the Enterprise Vegetation Management Department. I oversee PG&E's Electric VM Asset Strategy and Analytics team. My responsibilities include the formulation of 2024-2028 VM Plan as associated Wildfire Mitigation Plan strategy and support. I also participate in benchmarking activities with other utilities and sponsor research at California universities, and/or other utility industry experts that support VM programs to gain a better understanding of where and what VM work should be performed in order to mitigate the risks that vegetation creates with our assets. I have also provided testimony and witness support for VM activities in PG&E rate cases, including PG&E's prior Wildfire Mitigation and Catastrophic Event applications and General Rate Case applications.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Science in Forestry from the University of Peshawar and a Master of Science in Forestry from the University of Peshawar. I am a Certified Arborist, Utility Specialist, Tree Risk Assessment Qualified – International Society of Arboriculture, and a Certified Tree care Safety Professional, Certified Utility Safety Professional, Certified Worker Occupational Safety and Health Specialist – University of California, Berkeley, California Occupational Safety and Health Administration (OSHA) 30 and OSHA 10 Certified and Certified Project Manager – Stanford Center for Professional Development. I have worked in the utility VM field for 22 years and have been with PG&E since 2008. I have held progressive responsibility and Management assignments in PG&E's VM Maintenance programs. The management roles I have held include Drought Emergency Response and Routine Programs, Supervisor, Operation Manger, and

Senior Operations Manager. Additional roles include Senior Manager of Field Safety in Electric Operations, Senior Manager VM Asset Strategy and Analytics, leading to my current role.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Wildfire Rate Relief Bond:

- Chapter 4, "Customer Benefits":
  - Sections A and D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SHANNON L. SIMS

Q 1 Please state your name and business address.

A 1 My name is Shannon L. Sims, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Cost Recovery and Regulatory Analysis Expert in the Energy Accounting Department at PG&E. My responsibilities include developing testimony in support of proceedings filed at the California Public Utilities Commission on matters related to cost recovery.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in business administration from the University of California at Berkeley. I received my certified public accountant license in the state of California while working for Deloitte & Touche LLP. I began my career with PG&E in 2001 as a Senior Accounting Analyst within the Technical Accounting section of the Controllers' Department. I joined the Regulatory Affairs Department in 2004. In this department, my responsibilities included project managing and drafting PG&E's Annual Electric True-Up and Annual Gas True-Up advice letters. I rejoined the Controllers' Department in 2017 and assumed my current position in 2019.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Wildfire Rate Relief Bond:

- Chapter 6, "Ratemaking Mechanisms."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TIM B. WEDLAKE

Q 1 Please state your name and business address.

A 1 My name is Tim B. Wedlake, and my business address is Pacific Gas and Electric Company (PG&E), 300 Lakeside Drive, Oakland, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am a Principal Tax Analyst on the Research, Audits and Planning Team in the Tax Department at Pacific Gas and Electric Company. I primarily manage PG&E's fixed asset tax depreciation and deferred tax system (PowerTax) and its related work products.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Finance from California State University, Hayward in 1980, and received a Master's degree in Finance from the same institution in 1982. In 1992, I received a Juris Doctor degree from Hastings College of the Law, University of California,[1] in San Francisco. I am licensed to practice law in California. From 1983 to 1989, I was employed by Pacific Bell in the Budget Department and Tax Department in a management capacity. I have designed and implemented various budget and tax computer models. Prior to my employment with PG&E, I worked as a consultant for the PG&E Tax Department on a variety of fixed asset tax issues.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's Wildfire Rate Relief Bond:

- Chapter 5, "Taxation."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

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[1] Now known as the University of California Law San Francisco.