BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	Application 22-05-015
And Related Matter.	Application 22-05-016

PETITION OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 M) FOR MODIFICATION OF DECISION 24-12-074

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I. INTRODUCTION

Pursuant to Rule 16.4 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission" or "CPUC"), Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") (collectively, the "Companies") hereby submit this Petition for Modification of Decision ("D.") 24-12-074 ("Petition") issued in the above-referenced proceeding on December 23, 2024. Consistent with Rule 16.4(d), this Petition is filed within one year of the effective date of D.24-12-074 ("Decision").

SoCalGas and SDG&E request modification of the Decision to incorporate a post-test year mechanism that aligns with the Commission's stated principle "that utilities should be provided with a fair opportunity to earn their authorized rate of return, while ensuring rates are just and reasonable and do not impose undue burden on ratepayers."[1] While the Commission's

[1] D.24-12-074 at 4.

express intent was to adopt a post-test year ("PTY") or "attrition"[2] mechanism in the Decision that would allow SoCalGas and SDG&E to recover their authorized capital-related costs,[3] the effect of the actual mechanism adopted in the Decision is to deprive the Companies from recovering the capital-related costs authorized in the Decision. This Petition seeks to correct this unintended error.

II. SUMMARY OF PETITION

SoCalGas and SDG&E submit this Petition for Modification of D.24-12-074 on the grounds that the Commission adopted a one-part post-test year mechanism for 2025-2027, which does not enable a utility to recover its authorized capital-related costs. This Petition demonstrates that the one-part post-test year mechanism adopted in the Decision was based on three misconceptions of fact—(1) that a 3% escalation of revenue requirement would be sufficient to allow the Companies' to cover their operating expenses, capital-related costs, and a reasonable return on their rate base;[4] (2) that Operations and Maintenance ("O&M") and capital costs impact the revenue requirement in the same way and therefore can be addressed with a one-part post-test year mechanism;[5] and (3) that the Companies failed to demonstrate their capital additions (*i.e.*, new additions to plant in service included in rate base) exceeded depreciation.[6]

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[2] The term "attrition" and "post-test year" are used synonymously herein. As explained in D.20-01-002 footnote 13, "[t]he term 'attrition' is used in reference to possible effects on utility earnings in the years between rate cases."

[3] D.24-12-074 at Conclusions of Law ("COL") 307 at 1084 ("The 3 percent increase in Post-Test Year (PTY) revenue requirement . . .is reasonable **because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base**. . . .")(emphasis added).

[4] *Id.*

[5] *See Id.* at 901 (adopting a one-part post test year mechanism for O&M and capital of 3% increase to PTY GRC base margin revenue).

[6] *See Id.*at Findings of Fact ("FOF") 438 at 1027 ("Sempra Utilities has not demonstrated the need for additional funds in the post-test years to account for anticipated growth in capital additions in excess of depreciation.").

These stated facts and conclusions, which expressly formed the basis for the Decision's post-test year mechanism, are demonstrably incorrect. Because the Decision expressly states that the adopted post-test year mechanism will allow SoCalGas and SDG&E to recover their capital-related costs, the Companies believe the resulting impact was unintended by the Commission and that the Decision should be modified to align with the stated intent of the Commission to allow the Companies to recover their approved capital-related costs.[7] It is now clear that the adopted one-part attrition mechanism does not and will not allow the Companies to fully collect the return of their capital investments (*i.e.*, depreciation), much less a return on their capital investments (*i.e., rate of* return), during the three post-test years of their Test Year ("TY") 2024 General Rate Case ("GRC") cycle. Absent Commission action, this revenue shortfall or "missing money" will remain unrecovered despite customers benefitting from Commission-authorized—but underfunded—capital investments that the Companies make in the post-test years. For both Companies, the missing depreciation expense and capital-related revenue requirement shortfall total approximately $5 billion of inadequately funded recurring capital projects over the post-test year period. This is not a just and reasonable level of capital expenditures under California Public Utilities Code ("Pub. Util. Code") Section ("§") 451 for the Companies to fulfill their obligation to provide safe and reliable service.

The Commission recognized the significance of this issue in approving a two-part mechanism in Southern California Edison Company's ("SCE") recent TY 2025 GRC Decision,

[7] *Id.* at COL 307 at 1084 ("The 3 percent increase in Post-Test Year (PTY) revenue requirement . . .is reasonable because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base. . . .").

D.25-09-030,[8] after initially including a one-part attrition mechanism in the proposed decision.[9] SCE's final decision explicitly acknowledges that a two-part attrition mechanism is reasonable because O&M and capital-related costs affect revenue requirement differently,[10] thus acknowledging that a one-part mechanism—the same mechanism adopted in D.24-12-074—is problematic. There is no basis for treating the utilities differently in this regard and ordering SoCalGas and SDG&E to utilize an attrition mechanism that the Commission has subsequently acknowledged is deficient.

The record evidence, the Rate Case Plan, and sound policy support the adoption of a two-part post-test year mechanism. In this Petition and the supporting declarations, SoCalGas and SDG&E further provide new factual evidence of the actual impacts of the post-test year mechanism since the Decision was adopted.[11] Significant negative financial impacts will persist and grow over the remainder of the TY 2024 GRC cycle.

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[8] *See also* Pacific Gas and Electric Company's ("PG&E") TY 2023 GRC Decision, D.23-11-069 at 706-716 (adopting a two-part attrition year mechanism).

[9] *Compare* Proposed Decision on Test Year 2025 GRC for SCE (filed July 28, 2025) (proposing a one-part post-test year mechanism of a 3% increase to the base revenue requirement for each attrition year) *with* D.25-09-030 at 843 (recognizing that O&M expenses and capital costs affect the revenue requirement differently and therefore adopting a two-part post-test year mechanism).

[10] D.25-09-030 at 843.

[11] Declaration of Khai Nguyen on Behalf of Southern California Gas Company in Support of the Petition for Modification of D.24-12-074 ("Nguyen Declaration") at Attachment B; Declaration of Melanie E. Hancock on Behalf of San Diego Gas & Electric Company in Support of the Joint Petition for Modification of D.24-12-074 ("Hancock Declaration") at Attachment C; Declaration of Ryan Hom on Behalf of Southern California Gas Company and San Diego Gas & Electric Company in Support of the Joint Petition for Modification of D.24-12-074 ("Hom Declaration") at Attachment D; Declaration of Bill G. Kostelnik on Behalf of Southern California Gas Company in Support of the Joint Petition for Modification of D.24-12-074 ("Kostelnik Declaration") at Attachment E; Declaration of Jonathan T. Woldemariam on Behalf of San Diego Gas & Electric Company in Support of the Joint Petition for Modification of D.24-12-074 ("Woldemariam Declaration") at Attachment F; Declaration of Michael W. Foster on Behalf of Southern California Gas Company in Support of the Joint Petition for Modification of D.24-12-074 ("Foster Declaration") at Attachment G; Declaration of Rachelle R. Baez and Michael W. Foster on Behalf of San Diego Gas & Electric Company in Support of the Joint Petition for Modification of D.24-12-074) ("Baez/Foster Declaration") at Attachment H.

To address the unintended consequence of the errors in the Decision, the Commission should grant this Petition and adopt a two-part attrition mechanism for the post-test year period (January 1, 2025 through December 31, 2027) that permits recovery of the PTY capital-related costs authorized in D.24-12-074. The Companies request a capital-related revenue requirement calculated using a seven-year average of capital additions (2018-2021 recorded and 2022-2024 forecasted), escalated by 3%. A seven-year average based on both historical and forecasted capital additions is consistent with the Companies' settlement agreement with Cal Advocates in Track 1 of this proceeding, and the Companies' TY 2019 GRC Decision.[12] This proposed approach is also consistent with SCE's TY 2025 GRC Decision, in which the Commission authorized the same two-part attrition mechanism as approved in SCE's prior GRC Decision (TY 2021).[13]

The Companies demonstrate below that their requested relief of a two-part attrition mechanism for years 2025-2027 is reasonable. The Companies further propose to implement a final decision on this Petition by amortizing funds that accumulate in their respective General Rate Case Memorandum Accounts ("GRCMA") beginning in August 2026.

III. STANDARD FOR MODIFICATION OF A FINAL COMMISSION DECISION

California Public Utilities Code Section 1708 authorizes the Commission to "rescind, alter, or amend any order or decision made by it" after providing proper notice to the parties and

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[12] *See* D.19-09-051 at COLs 106-109 at 774 (finding it reasonable to apply different PTY mechanisms for O&M and capital and that the mechanism for capital additions be based on seven-year average of recorded and forecasted capital additions); Joint Motion of SoCalGas, SDG&E, and the Public Advocates Office for Adoption of Settlement Agreements Resolving Various Issues in the 2024 GRC (October 24, 2023) at Attachment A, p.20-21.

[13] D.25-09-030 at 846.

an opportunity to be heard.[14] Rule 16.4 of the Commission's Rules of Practice and Procedure governs the filing of a petition for modification, and requires in relevant part:

> (b) A petition for modification of a Commission decision ***must concisely state the justification for the requested relief and must propose specific wording to carry out all requested modifications to the decision.*** Any factual allegations must be supported with specific citations to the record in the proceeding or to matters that may be officially noticed. Allegations of new or changed facts must be supported by an appropriate declaration or affidavit.[15]

The Commission has broad authority to grant a petition for modification.[16] To that end, the Commission has identified various valid grounds for exercising its broad discretion under Rule 16.4, including but not limited to, new facts, a material change in conditions, or where the Commission proceeded on a basic misconception of law or fact.[17] The Commission has also stated that reconsideration of its policy determination alone is sufficient basis for granting a petition for modification.[18] Some Commission decisions have expressed that a petition for modification should only be exercised in "extraordinary circumstances."[19] Other decisions have sought new facts or changes that create a "strong expectation that we would make a different decision based on these facts and circumstances."[20] This Petition to modify D.24-12-074 not only satisfies these standards but also provides ample justification for the relief requested given

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[14] Pub. Util. Code § 1708.

[15] Commission's Rules of Practice and Procedure, Rule 16.4(b)(emphasis added).

[16] D.17-12-006 at 9; *See* Pub. Util. Code § 1708.

[17] D.17-12-006 at 10-11.

[18] D.05-07-047 at 3-5 (the Commission's reconsideration of its policy position was sufficient basis for granting SDG&E's petition for modification even though no new or changed facts were alleged, finding that "there is no requirement for new or changed facts before a petition for modification may be granted" and "nothing in section 1708 or in Commission precedent prohibits us from reconsidering our policy determinations, so long as due process is satisfied and there is an evidentiary record to support the determinations upon reconsideration.").

[19] D.03-10-057 at 17-18.

[20] D.17-12-006 at 14.

the extraordinary and seemingly unintended impact of D.24-12-074's imposition of a one-part post-test year mechanism.

IV. BACKGROUND

A. Capital Costs and Revenue Requirement

The Commission states in its Rate Case Plan that the "GRC is a proceeding in which the Commission authorizes an investor-owned utility to recover through rates the reasonable capital investment costs and annual expenses necessary to operate and maintain its facilities and equipment in a safe and reliable manner."[21] The Commission further states, "the general rate case proceeding is viewed as the embodiment of what is often described as the 'regulatory compact.'"[22] The regulatory compact is summarized by the Commission as follows:

- Utilities accept the obligation to serve and charge regulated cost-based rates, and customers accept limited entry (*i.e.*, loss of choice) in exchange for protection from monopoly pricing.
- Under this agreement, the utility is provided the opportunity to recover its actual legitimate or prudent costs—determined by a public examination of the utility's outlays—plus a fair return on capital investment as measured by the cost of obtaining capital in a competitive capital market.
- Investors will only provide capital for provision of utility services if they anticipate obtaining a return that is consistent with returns they might expect from employing their capital in an alternative use with similar risk.
- Customers will only accept utility rates if they perceive that the rates fairly compensate the utility for its costs, but are not excessive as a result of the utility taking advantage of its privileged position.[23]

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[21] D.20-01-002 at 8.

[22] *Id.* at 10.

[23] *Id.* at 10-11, citing Edison Electric Institute, *Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation*, (June 2012) at 6, *available at*: https://www.ourenergypolicy.org/wp-content/uploads/2012/09/COSR_history_final.pdf.

Thus, pursuant to the regulatory compact, utilities are entitled to recovery in rates of their prudent costs plus a fair return on capital investments.[24] "Revenue Requirement is a formula that calculates the total annual revenue that a utility must earn in order to recover the costs of providing service plus a reasonable rate of return."[25] Commission staff has explained that "[t]he establishment of a utility's revenue requirement is the basis for setting the overall level of the utility's rates. Revenue requirement is the amount of gross revenues needed by the utility to cover its operating expenses, book depreciation, return, taxes, etc."[26] This is not only part of the regulatory compact, but is also mandated by Pub. Util. Code Sections 451, 454, and 728 requirements to establish just and reasonable rates. It is also affirmed by California Supreme Court and California Court of Appeals decisions.[27]

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[24] *See also Bluefield Waterworks & Imp. Co. v. Pub. Service Comm. of W. Va.,* 262 U.S. 679, 690 (1923) ("There must be a fair return upon the reasonable value of the property at the time it is being used for the public.") (internal citations omitted).

[25] United States Agency for International Development, *Primer On Rate Design For Cost-Reflective Tariffs*, (January 2021), *available at*: https://pubs.naruc.org/pub.cfm?id=7BFEF211-155D-0A36-31AA-F629ECB940DC at 10, citing footnote 3, Greer, Monica, *Chapter 10 - Efficient Pricing of Electricity*, (2011), *available at:* https://doi.org/10.1016/B978-1-85617-726-9.00010-8.

[26] CPUC - Policy & Planning Division, *Utility General Rate Case – A Manual for Regulatory Analysts*, (November 13, 2017) at 6-7.

[27] *Southern California Gas Co. v. Pub. Util. Comm'n* (1979) 23 Cal.3d 470, 476 ("The basic principle [of ratemaking] is to establish a rate which will permit the utility to recover its cost and expenses plus a reasonable return **on the value of the property devoted to public use**.")(emphasis added); *Ponderosa v. Pub. Util. Comm'n* (2011) 197 Cal.App.4th 48, 52; *Los Angeles v. Pub. Util. Comm'n* (1972) 7 Cal.3d 331, 346 ("The basic approach of the [C]ommission in rate making . . . is to take a test year and determine the revenues, expenses, and investment for the test year.").

Pursuant to the Rate Case Plan, the annual revenue requirement calculation[28] is as follows:

<u>Annual Summary of Earnings</u>

Line no.		
1		Authorized O&M Expenses
2	plus	Return on Rate Base
3	plus	Depreciation Expense
4	plus	Taxes
5	equals:	Annual Customer Revenue Requirement

As shown above, the revenue requirement consists of several components:

- <u>O&M Expenses (Line 1):</u> O&M expenses are the day-to-day expenses that a utility incurs to provide services. O&M expenses are typically annual expenses that are recurring in nature and that are associated with operating the utility. Examples of O&M expenses include employee salaries and inspections on equipment that are completed on a recurring cycle. The revenue requirement is intended to recover the annual forecasted O&M costs in the period they are incurred.
- <u>Capital-Related Costs (Lines 2-4):</u> The revenue requirement does not include the total forecasted upfront capital costs that the utility expects to pay to construct or complete a capital project or program. Instead, the revenue requirement includes only a portion of those costs annually, referred to as the capital-*related* costs, *i.e.,* annual depreciation, tax, and return on investment, associated with each relevant year of the used and useful life of in-service capital assets. Specifically:

[28] Summary of Earnings is an income statement view from the Results of Operations ("RO") model to summarize test year revenue requirement.

- Line 2 is the return on rate base. This is often referred to as return *on* capital. It is calculated by multiplying rate base[29] by the authorized rate of return as established through separate Cost of Capital proceedings.
- Line 3 is depreciation expense. Depreciation is often referred to as return *of* capital or return *of* the investment. It is the annual reduction in a utility's plant in-service balance included in rate base reflecting its usage and amount necessary to recover the investment over the useful life of the asset. In other words, it is the mechanism by which the utility recovers its up-front capital cost of the asset from customers over the asset's useful life.
- Line 4 is taxes. It represents taxes payable by the utility associated with the capital investment.

For additional context, capital investments represent project and program costs to build assets that are used and useful for multiple years. Each capital investment addresses a different component of the system. Even routine capital projects that replace a given number of widgets per year, for example, are not the same widget being replaced each time (like O&M) but could be a new widget in a different location. Because capital projects have a start and end date and have useful lives greater than one year, the costs can vary from year to year corresponding to the project lifecycle. The capital costs that are spent during the construction phase of the project are referred to as capital expenditures. Those capital expenditures, once the asset is placed into service and it is used and useful, become what is referred to as capital additions or plant in service. Capital additions are the total costs of assets placed into service, recorded as "plant" on

[29] Rate base is the "net value of plant in service plus working capital." *See* CPUC - Policy & Planning Division, *Utility General Rate Case – A Manual for Regulatory Analysts*, (November 13, 2017) at 19.

a utility's balance sheet, and depreciated over the asset's useful life. Capital additions are recovered over time through depreciation expense (*i.e.*, return of investment) as a key component of the revenue requirement.

Based on the foregoing, the annual revenue requirement represents the cost of utility service plus an opportunity to earn a fair rate of return on capital investment.

B. The GRC Procedural Process and Necessary Elements of a Utility's Application

The process and procedure for GRCs is prescribed in the Commission's Rate Case Plan ("RCP") and is the roadmap for the Commission to authorize an appropriate revenue requirement. "The purpose of the RCP is to ensure that complex and financially significant GRC proceedings follow a predictable schedule that balances the need for timely Commission decisions with procedural fairness for all parties."[30]

The RCP also outlines information required to be included in GRCs. One requirement is to present "base year historical and estimated data and subsequent years with evaluation of changes up to and including the test year."[31] This means that utilities are required to provide recorded base year data and forecasts up to and including the test year. For post-test year ratemaking, the RCP requires evidence supporting the requested attrition allowance, but notes the differences between test year and post-test year ratemaking, as follows:

> The Commission's [GRC] decision is based on its extensive review of the test-year forecasts. The post-test year revenue requirements are typically determined by (1) escalating the test-year O&M expenses, ***and*** (2) authorizing capital expenditures at a level determined by either (i) applying additional escalation

[30] D.20-01-002 at 2.

[31] D.07-07-004, at Appendix A.

> factors, or (ii) further review of the applicant utility's actual capital budgets for those years.[32]

Thus, the RCP requires detailed information to develop test year revenue requirement and recognizes that attrition year funding is typically determined using a two-part mechanism—one-part for O&M and another for capital expenditures.

C. Overview of the Authorized Post-Test Year Mechanism in D.24-12-074

The Commission issued D.24-12-074 on December 23, 2024, approving a TY 2024 revenue requirement for the Companies and a post-test year mechanism for years 2025 through 2027. Consistent with its RCP, the Commission established a test year 2024 revenue requirement based on an "extensive review" and "examination of detailed utility budgets."[33] For the post-test years, however, the Commission adopted a one-part mechanism consisting of a "base margin revenue (O&M and capital revenue requirement) increase of 3 percent each year for 2025, 2026, and 2027 plus certain wildfire mitigations, including undergrounding and covered conductor."[34] The Decision reasons that 3% escalation on base margin revenue, including both capital and O&M, "is reasonable because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base."[35] The Decision further reasons that "Post-Test Year Ratemaking is not meant to replicate a test year analysis or cover all potential cost changes to guarantee the utility's rate of return during the attrition years. Its purpose is to reduce economic volatility between test years so that a well-managed utility can provide safe and reliable service while maintaining financial integrity."[36]

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[32] D.20-01-002 at 8 (emphasis added).

[33] *Id.* at 8, 37.

[34] D.24-12-074 at 895-896.

[35] *Id.* at COL 307 at 1084.

[36] *Id.* at FOF 434 at 1026; *see also* D.20-01-002 at 41.

As explained below, the Decision's adopted one-part post-test year mechanism for capital and O&M does not, in fact, allow the Companies to recover a significant portion of capital costs or rate of return associated with approved capital projects. Additionally, the Decision is creating, rather than reducing, economic volatility for the Companies in the post-test years and jeopardizing their ability to maintain financial integrity while providing safe and reliable service consistent with the regulatory compact.

V. DISCUSSION

A. The Authorized One-Part Post-Test Year Mechanism Fails To Fund Commission-Approved Capital Additions

Although the Decision authorizes the Companies' revenue requirement for the four-year GRC cycle, the approved one-part post-test year mechanism fails to provide sufficient revenue requirement to fund capital investments in the 2025-2027 post-test years. The one-part post-test year mechanism authorized for the Companies in the Decision escalates *both* the test year 2024 O&M and the test year 2024 capital revenue requirement by about 3%.[37] The Companies request the Commission modify the Decision to acknowledge the fact that capital costs and O&M expenses affect the revenue requirement differently and should not be subject to the same post-test year escalation.[38] The Companies do not dispute the mechanism authorized for determining PTY O&M revenue requirement. Nor are the Companies disputing the escalation percentage of 3% authorized in the Decision or the capital budget-based exception for SDG&E's wildfire mitigation programs of Strategic Undergrounding and Covered Conductor. This Petition is limited to the Decision's determination that capital and O&M should be escalated in the same manner for purposes of the post-test year mechanism. The Decision is based on a

[37] D.24-12-074 at 901.

[38] D.25-09-030, FOF 842 at 950.

misunderstanding of the treatment of O&M and capital in the post-test years and should be modified accordingly and in alignment with the Rate Case Plan. That misunderstanding of fact, and the policy implications of that misunderstanding, have since been recognized by the Commission in applying a two-part post-test year mechanism to SCE's TY 2025 GRC Final Decision.

A one-part post-test year mechanism that escalates capital-related revenue requirement at the same level as O&M is problematic because O&M expense and capital costs are accounted for in very different ways, as acknowledged in SCE's TY 2025 GRC Decision and the RCP.[39] While O&M expenses are generally annual, capital-related costs are based on depreciation schedules for the useful life of the capital investment. Thus, while the annual nature of O&M expenses make the test year revenue requirement, with an inflation-based escalator, a suitable proxy for the post-test years, the same is not true for capital costs. Test year capital-related costs, such as depreciation, will continue into the post-test years, but new capital assets will also be placed into service each post-test year with their own associated capital-related costs that cannot be suitably accounted for with the Decision's inflation-based escalator.

When the Commission approves a capital project, the utility funds the up-front investment for that project on behalf of its customers and receives full recovery of and on that investment over the life of the asset via depreciation, taxes and return that are passed on to the customer in rates. If capital-related costs for the authorized capital investment are not included in the revenue requirement for one or more years during the post-test years, the utility never recovers the full cost of the capital investment, jeopardizing the financial health of the utility. Further, it is important to note that the "missing money" issue is not merely shortchanging the

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[39] *Id.;* D.20-01-002 at 8; *see also* D.19-09-051 at COL 106 at 774.

utility on its opportunity to earn a return **on** the investment (or profit); rather, this is a deficit in depreciation expense (return **of** investment).

To illustrate this issue, assume the Commission approved an ongoing, recurring capital program in the GRC. This capital program is a $50 million investment in each year of the GRC cycle, with a 50-year useful life, and is being placed in-service in the same year the investment is made beginning in TY 2024. For the $50 million capital investment made in 2024, the utility should collect the applicable depreciation associated with that project in each year of its 50-year life, or about $1 million per year ($50 million capital program divided by the 50-year useful life), plus taxes and return. Applying the Decision's post-test year mechanism, the 2024 $50 million capital program is accounted for in the test year as an in-service project, and thus the $1 million collected beginning in the test year for capital-related costs would be escalated by 3%. Thus, the utility would collect $1.03 million in the first post-test year (2025), $1.06 million in 2026, and $1.09 million in 2027, or a total of $4.18 million over the four-year GRC cycle. In other words, the utility only is left with $180,000 in revenue to fund depreciation related to new capital in the post-test years beyond the depreciation associated with the one $50 million capital investment in the test year. For the $50 million capital investment in the test year, this is an appropriate return of the utility's depreciation expense ($1 million/year) and the opportunity for a return on its investment.

In this example, however, the Commission approved a recurring capital program, with a $50 million investment *each year* of the GRC cycle, not just the test year. Accordingly, the following depreciation costs are associated with the approved capital program:

- The depreciation associated with the first (test year) $50 million investment is $1 million per year, starting in 2024, or $4 million over the GRC cycle (line 2 below).

- The second $50 million investment made in 2025 also requires $1 million per year in depreciation, starting in 2025, or $3 million over the GRC cycle (line 3 below).

- The third $50 million investment made in 2026 requires $1 million per year in depreciation, starting in 2026, or $2 million over the GRC cycle (line 4 below).

- The final year's investment over the GRC cycle requires $1 million per year in depreciation in 2027, or $1 million over the GRC cycle (line 5 below).

For simplicity, the table below illustrates the recurring $50 million capital program example, specifically focused on depreciation expense only, the lack of funding under the adopted post-test year mechanism, and how it becomes increasingly exacerbated in each successive post-test year.

Table 1. Recurring Capital Program Example ($ millions)

Line No.	2024	2025	2026	2027	Total	Notes
Recurring Capital Program Investment						
1	$50	$50	$50	$50	**$200**	
Needed Depreciation Expense Component of Capital Revenue Requirement						
2	$1.00	$1.00	$1.00	$1.00	**$4.00**	In-service Jan. 1, 2024
3		$1.00	$1.00	$1.00	**$3.00**	In-service Jan. 1, 2025
4			$1.00	$1.00	**$2.00**	In-service Jan. 1, 2026
5				$1.00	**$1.00**	In-service Jan. 1, 2027
6 (2+3+4+5)	**$1.00**	**$2.00**	**$3.00**	**$4.00**	**$10.00**	
Authorized Depreciation Expense Component of Capital Revenue Requirement						
7	$1.00	$1.03	$1.06	$1.09	**$4.18**	
Shortfall of Authorized Depreciation Expense Component of Capital Revenue Requirement						
8 (7-6)	-	($0.97)	($1.94)	($2.91)	**($5.82)**	

Completion of a $50 million capital program each year of the GRC cycle requires a depreciation expense of $10 million over the GRC cycle (line 6 in the table above) for the utility to recover its investment (return of investment) for that period. Yet, in applying the Decision's attrition mechanism to this example, the Decision would only authorize $4.18 million in revenue over the GRC cycle (line 7 in the table above). Therefore, in this example, over the four-year GRC cycle, the utility is denied recovery of $5.82 million of its capital investment through a shortfall of, or "missing" depreciation expense (shown in line 8 above). This is an investment that the utility will never recover because the post-test year revenue requirement fails to properly account for capital additions. And, as the utility makes investments that are unfunded in the post-test years, customers benefit from these assets while not paying the full cost.

The concept of missing capital-related costs (including depreciation, taxes and return on investment) caused by simply escalating test year revenue requirement for capital is exacerbated if the useful life of an asset is relatively short. For example, if the post-test year mechanism does not account for new capital with in-service dates in the post-test years, and the asset has a five-year useful life (like many technology and cybersecurity projects), then, as much of 3/5 of the cost of the prudent capital-related revenue requirement may _never_ be recovered.[40]

The misconception of fact that the Decision adequately funds approved capital projects, when it does not, underpins the Decision's Conclusion of Law,[41] ultimately results in legal issues as well. It is well-established that utilities are entitled to the return of their approved capital

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[40] Further, the Decision's language suggesting that the Companies should "fund" certain incremental capital additions via memorandum accounts (*see, e.g.,* D.24-12-074 at 901) is also a misconception of fact and law. A memorandum account does not actually "fund" capital-related costs; rather, it provides the utility with the opportunity to seek reimbursement for those costs at a later date. The Companies collect revenue requirement to help fund capital projects and, without those revenues returning to the Companies in the post-test years, the Companies must find other sources of funding, which comes at a cost. Further, the Decision authorizes certain capital projects and recurring capital programs, and placing the related capital costs associated with that capital projects and programs in a memorandum account subjects the utility to an ex-post standard of review that introduces risk and uncertainty to spending that has been authorized in this GRC. The Commission is thus authorizing certain costs as "reasonable" on the one-hand, while at the same time saying that it may find them "unreasonable" or "imprudently incurred" at a later date. Finally, not all of the "missing" capital costs have a related memorandum account in which they can be recorded. Thus, while some capital costs *may* be recovered in the future via an application for amounts recorded in a relevant memorandum account, not all such costs have a related memorandum account.

[41] D.24-12-074 at COL 307 at 1084 ("The 3 percent increase in Post-Test Year (PTY) revenue requirement . . .is reasonable **because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base**. . . .")(emphasis added).

investments, and an opportunity to earn a return on their investments.[42] By incorrectly concluding that capital projects were adequately funded, the Commission deprives the utilities of the ability to recover their investment, let alone a return on that investment – in contravention of longstanding precedent and established law.

B. The Decision Authorizes Approximately $5 Billion in Capital Investment During the Post-Test Years Without Authorizing Sufficient Recovery of Associated Capital Costs

This is not a theoretical problem. 74% of SoCalGas's authorized capital expenditures and 71% of SDG&E's are recurring in nature and are subject to the missing depreciation expense issue and capital-related revenue requirement shortfall identified above.[43] For both Companies, this totals approximately $5 billion of inadequately funded recurring capital projects over the post-test year period.[44] And this is pervasive in nearly every operational area for SoCalGas and SDG&E (*e.g.*, Electric Distribution, Gas Distribution, Gas Transmission, Gas Storage)[45] and is significant given that the capital-related revenue requirement is over half of the Companies' total revenue requirement.[46]

An example of a routine, authorized capital program is SoCalGas's Gas Transmission Cathodic Protection program, which was uncontested and approved by the Commission in the

[42] *Bluefield Waterworks & Imp. Co. v. Pub. Service Comm. of W. Va.*, 262 U.S. 679, 690 (1923); *see also Fed. Power Comm. v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (return on equity "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.").

[43] *See* Attachment D (Hom Declaration) at ¶ 7.

[44] *Id.*

[45] *Id.*

[46] *Id.* at ¶ 11.

Decision.[47] Cathodic protection protects pipelines from becoming corroded over time.[48] This program is necessary to maintain or improve the pipeline's cathodic protection system, extends the life of the pipeline, and maintains compliance with Title 49, Code of Federal Regulations ("CFR") § 192.463.[49] The Decision authorized $8 million in spending for 2022 and 2023 and $7 million in spending in 2024 for this ongoing Risk Assessment Mitigation Phase ("RAMP") item.[50] Because this is a recurring capital program, SoCalGas would expect to spend approximately these same amounts over each of the post-test years. However, due to the Decision's post-test year mechanism, SoCalGas is severely underfunded for capital-related costs in the post-test years (for both authorized capital projects and more significantly for the expected recurring capital expenditures made pursuant to the Cathodic Protection program and regulatory requirement). Such on-going programs are critical for the Companies to continue to provide safe and reliable service and yet the authorized post-test year mechanism does not enable the Companies to recover those costs (*i.e.*, return *of* investment) or provide a return *on* the Companies' investment, which further leads to insufficient revenues to actually fund the Companies' ongoing capital investments. In other words, the PTY structure itself hinders the Companies' ability to fulfill the obligation to serve customers under Pub. Util. Code § 451.

Accordingly, the one-part mechanism that simply escalates the test year capital revenue requirement at 3% adopted in the Decision is not an adequate or appropriate means to allow recovery of a utility's attrition year capital revenue requirement. To properly account for capital additions and the related annual depreciation expense in the authorized revenue requirement, the

[47] D.24-12-074 at 194. *See* Ex. SCG-06-CWP-R, Workpaper Group 003060.

[48] D.24-12-074 at 99.

[49] Ex. SCG-06-2R-E at CHB-74 to CHB-75.

[50] D.24-12-074 at 1041-1042.

post-test year mechanism must take into account the capital additions (used and useful capital investments) expected to be made in the post-test years and the depreciation expense associated with those additions. Without considering capital additions, the Decision's post-test year mechanism requires the Companies' shareholders to fund post-test year capital projects without a return of that investment via depreciation expense, tax, or return on the investment in capital, at least until the next TY 2028 GRC. Moreover, the utility will never be made whole for the depreciation expense, tax, or return that was omitted during this TY 2024 GRC cycle.[51]

C. The Authorized Post-Test Year Mechanism Only Partially Funds Approved Capital Projects With Test Year In-Service Dates

In addition to not providing sufficient funding for new capital assets placed in service during the post-year years, a post-test year mechanism based on escalating the test year revenue requirement does not fully fund capital assets placed in-service *during* the test year. In preparing the GRC forecast, the Companies forecast capital expenditures along with the dates the projects are estimated to be in-service as part of their GRC applications. If a given capital project's estimated in-service date is later than January 1 of the test year, it means that the test year revenue requirement for that capital project will be prorated based on the in-service date.[52]

For example, assume the Commission approves a project with a forecast of $100 million in capital expenditures and the project has a January 1, 2024 in-service date. This means that the revenue requirement for the test year should be a full year of capital-related costs since the asset

[51] *Bluefield Waterworks & Imp. Co. v. Pub. Service Comm. of W. Va.*, 262 U.S. 679, 690 (1923); *see also Fed. Power Comm. v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (return on equity "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.").

[52] In-service dates are typically estimated to be the end of the month; however, for ease of understanding, the Companies use the first date of the month as the in-service date. Rate base is then calculated based on a 13-month average.

will be in-service for all of test year 2024. The annual revenue requirement for the $100 million of capital expenditures is assumed to be $9 million.[53] If instead the estimated in-service date for this project is June 30 of the test year, the test year revenue requirement will be half of the annual amount because of the June 30 in-service date, or about $4.5 million. Because capital-related revenue requirement is collected annually over the life of the asset, beginning in year two of the GRC cycle, the utility will need the full $9 million of annual revenue requirement to service that asset. Based on the one-part mechanism authorized by the Decision, however, the utility would only receive the test year's pro-rated funding level of $4.5 million escalated by 3% (or $4.6 million). Table 2 below illustrates the difference in revenue requirement for a project forecast of $100 million in capital expenditure using a capital additions attrition mechanism compared to the Decision's attrition of 3%. Use of the two-part capital additions-based mechanism will provide the needed revenue requirement of $9 million in each post-test year while the mechanism approved in Decision results in a $12.7 million shortfall.

Table 2. Attrition Mechanisms Using an Example Project with a June In-Service Date

($ millions), Assumes June 2024 In-Service Date	**Test Year 2024**	**2025**	**2026**	**2027**	**Total**
Capital Expenditures	$100				$100
Revenue Requirement Based on Capital Additions Attrition Mechanism	$4.5	$9.0	$9.0	$9.0	$31.5
Revenue Requirement Based on 3% Attrition	$4.5	$4.6	$4.8	$4.9	$18.8
Shortfall	$0	($4.4)	($4.2)	($4.1)	($12.7)

[53] Estimated based on a long-lived operational asset (*e.g.,* gas pipeline) using the 2024 GRC Decision's Results of Operations model.

Table 3 below illustrates the impact on the revenue requirement for an asset that goes into service in January, June, and December of the test year through the GRC cycle when the Decision's 3% escalation mechanism is used. Revenue requirement is directly and significantly impacted by the in-service date.[54] In fact, if the in-service date is December 31 of the test year, there will be no authorized revenues for that project using the one-part mechanism authorized by the Decision.

Table 3. Example Project with Different In-Service Dates

($ millions), Assumes 3% attrition	Test Year 2024	2025	2026	2027
Capital Expenditures	$100			
Revenue Requirement for January 2024 in-service date	$9.0	$9.3	$9.6	$9.8
Revenue Requirement for June 2024 in-service date	$4.5	$4.6	$4.8	$4.9
Revenue Requirement for December 2024 in-service date	$0	$0	$0	$0

For anything other than assets in-service as of January 1 of the test year, a capital attrition mechanism that is based on the test year revenue requirement will not make the Companies whole in the post-test years for their investments.[55] Even for capital projects with test year in service dates, the utility will be collecting less than the full annual revenue requirement required to recover the total cost of this capital project.[56] Thus, due to the PTY mechanism's structure, the utility is significantly underfunded for its overall capital needs during the GRC cycle.

Around 20% of SoCalGas and SDG&E's approved capital expenditures had estimated in-service dates between January 31 through December 31 in 2024, totaling over $1 billion in

[54] *See* Attachment D (Hom Declaration) at ¶¶ 8-10.

[55] *Id.* at ¶ 9.

[56] *Id.*

capital expenditures.[57] Because these capital expenditures have an in-service date beyond January 1, the Companies are unable to recover sufficient revenues under the one-part mechanism.[58] Moreover, in December 2024 alone, SoCalGas and SDG&E forecasted that $223 million and $327 million in capital expenditures respectively, would go into service.[59] None of the depreciation expense, or other capital-related expenses, associated with those December 2024 capital projects is recovered in revenue requirement for the entirety of the 2024 GRC cycle. In other words, the only fully-funded authorized capital investments based on the current one-part attrition mechanism are those that were in service as of January 1, 2024.[60] All other capital investments placed in-service during this GRC cycle are insufficiently funded.[61]

An example of a project with a December 2024 in-service date is SDG&E's uncontested Coronado 69/12kV Transformer Replacement project.[62] This project, identified as a RAMP item that mitigates safety and reliability risks, replaces a 40-year-old transformer that shows signs of failure.[63] Not only does the project provide critical load support for 11,000 residents, but it also alleviates environmental concerns due to equipment gassing concerns and provides secondary oil containment.[64] This project was approved and authorized in the Decision,[65] and yet—under the current post-test year mechanism—SDG&E will not receive recovery of the annual revenue

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[57] *Id.* at ¶ 10.

[58] *Id.* at ¶ 9.

[59] *Id.* at ¶ 10.

[60] *Id.* at ¶ 9.

[61] *Id.*

[62] D.24-12-074 at 425-426.

[63] Ex. SDG&E-11-R at OR-136.

[64] *Id.* at OR-136 - OR-137.

[65] D.24-12-074 at 425-426, FOF 151 at 986.

requirement associated with this investment during the current GRC cycle. There are numerous other examples of projects with December 2024 in-service dates, including information system infrastructure programs, field hardware replacements, and substation rebuilds.[66]

D. Without Modification of the Post-Test Year Mechanism, SoCalGas and SDG&E Customers Will Be Harmed

In the Companies' TY 2024 GRC, the Commission authorized direct capital expenditures of $2.4 billion, $2.4 billion, $2.5 billion for years 2022, 2023, and 2024, respectively.[67] As explained above, the authorized test year revenue requirement was based on a detailed review of capital expenditures, but the post-test year authorized revenue requirement does not provide adequate capital-related costs for these authorized projects. Moreover, the Commission did not explicitly authorize capital expenditures in the post-test years, but it is typically understood that the post-test year revenue requirement will cover capital costs for explicitly authorized capital expenditures, plus capital investment that will continue into the post-test years, despite not being explicitly authorized. For instance, there is an expectation that capital expenditures for approved projects that are on-going, such as the Cathodic Protection program, will continue into the post-test years. Starting with the authorized revenue requirements for 2025-2027, the Companies calculated the level of capital expenditures that the authorized attrition revenue requirements could sustain. The capital expenditures associated with the authorized revenue requirement for 2025, 2026, and 2027 are shown in Figure 1 below.

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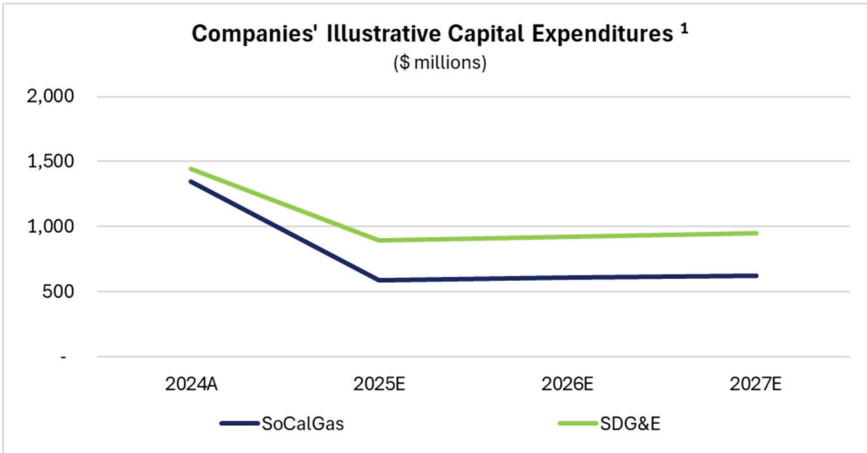
[66] *See* 2024 GRC Decision RO model.

[67] Does not include loaders or overheads. Amounts in constant 2021 dollars.

Figure 1. Impact of Authorized Capital Attrition Mechanism on Capital Expenditure[68]



[1] Displays authorized capital expenditures for 2024 and illustrative estimates for 2025-2027.

While the authorized revenue requirement grows modestly through the GRC cycle, the capital expenditures associated with the authorized revenue requirement dramatically drops in 2025-2027, as shown in Figure 1 above.[69] Using the information in Figure 1, to manage within the authorized revenue requirement, the Companies would be required to decrease combined capital expenditures from nearly $2.8 billion authorized in TY 2024 to about $1.5 billion per year on average during the post-test years.[70] That equates to an average annual capital expenditure decrease of 45%, or approximately $1.3 billion per post-test year, and a total decrease of approximately $3.8 billion in capital expenditures over the TY 2024 GRC cycle.[71]

This is not a reasonable level of capital expenditures for the Companies to fulfill their obligation to provide safe and reliable service.[72] Given the Commission's stated principle in the

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[68] Attachment D (Hom Declaration) at ¶ 13.

[69] *Id.* ¶¶ 13, 15.

[70] *Id.* ¶¶ 13-16.

[71] *Id.* at ¶¶ 15-16.

[72] *See, e.g.,* Attachment E (Kostelnik Declaration) at ¶ 12; Attachment F (Woldemariam Declaration) at ¶¶ 18, 22-26; *see also* Tr. Vol. 26 at 4379:8-21 (Maryam Brown) ("These PHMSA requirements have been adopted by the CPUC, and more specifically SED. The CPUC's delegated authority from PHMSA rests on an expectation and an obligation that these federal requirements will be authorized, funded, and

Decision that "utilities should be provided with a fair opportunity to earn their authorized rate of return,"[73] the Companies do not believe this result was intended by the Commission in authorizing the one-part post-test year mechanism. This belief is further evidenced by language in the Decision that indicates an apparent misconception of fact and law in concluding that "[t]he 3 percent increase in Post-Test Year (PTY) revenue requirement . . .is reasonable because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base. . . ."[74] As demonstrated above, the mechanism does not allow SoCalGas and SDG&E to cover their capital-related costs in the post-test years. In the proceeding, the Companies testified that a post-test year mechanism based on escalating revenue requirement "will not provide reasonable and sufficient funding for operating expenses and capital investments."[75] Figure 1 illustrates this. In reality, the Companies will need to continue making some level of required investments for safety and reliability, but will not be allowed to recover adequate revenues to cover those investments.

The continued need for capital investment through the GRC cycle is critical. The underfunded capital-related costs, or "missing money," occurs when future depreciation expense is not set appropriately.[76] Drs. McDermott and Peterson describe this attrition problem of capital investment exceeding historical depreciation levels and resulting consequences in the

enforced. This PD authorizes the work to be done, as it must. But, the money to fund that work in the post-test years is not adequate. This mismatch, between the expectation to continue doing the capital work through the post-test years and the failure to fund that same level of work, sends a potentially dangerous mixed message. From the federal world that I spend time in, the term of art to describe this situation is 'an unfunded mandate.'")

[73] D.24-12-074 at 4.

[74] *Id.* at COL 307 at 1084.

[75] Ex. SCG-245 at 8 (lines 10-11).

[76] Attachment B (Nguyen Declaration) at ¶ 6; Attachment C (Hancock Declaration) at ¶ 6.

whitepaper, *Post Test Year Ratemaking: Timing, Attrition, and the Balancing of Interests*, attached hereto as Attachment I. Drs. McDermott and Peterson explain:

> In addition, as capital expenditures begin to outpace depreciation this only adds to the attrition problem. Again, looking at the gas industry, since 2011 capital expenditures have exceeded historic values due to increasing replacement costs to bolster the safety of the system which leads to attrition as measured by the difference between authorized returns and the earned returns for gas utilities.[77]
>
> …
>
> Because the utility has an obligation to serve, it must incur costs to serve customers even if it has no method for resetting prices. As a result, trade-offs are imposed on management that may require deferring capital expenditure or reducing non-revenue expenses that are under management's control, but which may have long-term, or even short-term, implications for service quality.[78]

Thus, if the PTYs are not sufficiently funded, tradeoffs must occur that will have implications for both customers and the Companies. Here, those implications would include deferring or scaling back important work to only what is mandated, stopping certain programs, and/or completing essential work without adequate funding – all of which could impact service for customers, create rate volatility, and result in higher borrowing costs and inability to earn the Companies' authorized rates of return.[79]

As the Companies near the end of their first post-test year, the level of capital funding from the authorized attrition mechanism has proved unsustainable. Since the Decision was

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[77] K. A. McDermott and C. R. Peterson, *Post Test Year Ratemaking: Timing, Attrition, and the Balancing of Interests* (December 8, 2025) ("McDermott and Peterson"), Attachment I at 9.

[78] *Id.* at 21-22.

[79] *See, e.g.,* Attachment E (Kostelnik Declaration) at ¶ 12; Attachment F (Woldemariam Declaration) at ¶¶ 18, 22-26; *see also* Tr. Vol. 26 at 4379:8-21 (Maryam Brown) ("These PHMSA requirements have been adopted by the CPUC, and more specifically SED. The CPUC's delegated authority from PHMSA rests on an expectation and an obligation that these federal requirements will be authorized, funded, and enforced. This PD authorizes the work to be done, as it must. But, the money to fund that work in the post-test years is not adequate. This mismatch, between the expectation to continue doing the capital work through the post-test years and the failure to fund that same level of work, sends a potentially dangerous mixed message. From the federal world that I spend time in, the term of art to describe this situation is 'an unfunded mandate.'")

issued, SoCalGas and SDG&E have experienced negative financial impacts. In January 2025, following the issuance of the Decision, S&P Global Ratings ("S&P") downgraded SoCalGas's credit rating from 'A' to 'A-'. S&P explained:

> The downgrade of SoCalGas reflects our expectation that the company's financial measures will remain consistently below our downgrade threshold of FFO to debt of 20%. After incorporating SoCalGas' rate case order, we expect its stand-alone FFO to debt to be 17%-19% through 2027… Furthermore, we expect the company to operate with negative discretionary cash flow throughout our forecast period, indicative of external funding needs.[80]

Thus, SoCalGas's financial measures, as calculated by S&P, fell below their downgrade threshold for SoCalGas. All else being equal, a lower credit rating will increase the cost of debt that will ultimately be borne by customers.[81]

For SDG&E there are also indications of deteriorated credit quality, as stated in Moody's Ratings ("Moody's") March 2025 credit opinion that the Decision's attrition rates introduced "regulatory uncertainty" and "tempers its A3 credit rating."[82] Additionally, under a section labeled "Credit Challenges," the credit opinion listed the following:

- Regulatory uncertainty following outcome of 2024 General Rate Case
- Adverse rate case decision could negatively affect financial metrics
- Pending CPUC decisions could limit cash flow visibility

[80] S&P Global, *Research Update: Sempra Outlook Revised to Negative, Ratings Affirmed; Southern California Gas Downgraded, Outlook Stable* (January 9, 2025), *available at:* https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/sourceId/13372819.

[81] *See* D.22-12-031 at 4.

[82] Moody's Ratings, *Credit Opinion: San Diego Gas & Electric Company* (March 10, 2025) at 1-2 ("The December 2024 CPUC final decision on SDG&E's rate increase request to address revenue requirement deficiencies for the test years 2024 and attrition rates for the 2025- 2027 period (Track 1) has introduced some regulatory uncertainty. This uncertainty will affect the utility's cash flow visibility and tempers its A3 credit rating.").

- Weakly positioned at the A3 rating level[83]

This evidence of deteriorated credit quality not only negatively impacts the Companies, but also their customers. All else being equal, credit rating downgrades lead to higher costs of debt for future debt issuances.[84] The higher costs of debt are passed on to customers as part of the Companies' authorized cost of debt in their Cost of Capital proceedings, increasing rates over the term of the bond.[85] The Companies commonly issue long-term debt (*i.e.*, bonds) with terms as long as 30 years, so increased debt costs can result in long-term rate impacts for customers.

Furthermore, because the Decision was issued at nearly the end of the test year, there was uncertainty with respect to 2024 GRC outcome, which required the Companies to make significant capital investment decisions without information or confirmation on the test year authorized revenue requirement. The result of this uncertainty is the Companies' capital expenditures in 2024 exceeded authorized levels.[86] The spending above-authorized in the test year, coupled with underfunding in the post-test years (missing money or shortfall), creates an untenable situation that undercuts the Companies' efforts to maintain safe and reliable service through the capital projects authorized in the Decision.

To stay within their authorized revenue requirements over the GRC cycle, the Companies will need to limit capital spending for the remainder of the GRC cycle.[87] Some of the projects and programs authorized by the Commission, even for safety and reliability, are not adequately funded. Many of these underfunded capital projects, such as Wildfire Mitigation and Pipeline

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[83] *Id.*

[84] *See* D.22-12-031 at 4.

[85] *See generally id.*

[86] A.21-05-014/A.22-05-016, Risk Spending Accountability Report of SoCalGas and SDG&E For 2024 (filed May 30, 2025) at 13.

[87] Attachment D (Hom Declaration) at ¶¶ 7, 11-16.

Safety Enhancement Plan ("PSEP") projects, were included in the Companies' RAMP Reports[88] because they mitigate the Companies' top safety and reliability risks, and key illustrative examples of underfunded capital projects are detailed below.

a. The PTY mechanism provides insufficient funding for critical Wildfire Mitigation Plan capital expenditures.

The Decision adopted a limited budget-based capital exception for SDG&E's Strategic Undergrounding and Covered Conductor wildfire mitigation programs.[89] All other capital programs, including other wildfire mitigation capital programs, are subject to the Decision's problematic one-part post-test year mechanism.[90]

As described in the declaration of Jonathan Woldemarim, SDG&E is obligated to perform ongoing capital investments as part of its Wildfire Mitigation Plan ("WMP").[91] In addition to being regulated by the Commission, SDG&E's wildfire mitigation activities are also regulated by the Office of Energy Infrastructure Safety ("OEIS" or "Energy Safety"), which, among other things, reviews and approves SDG&E's WMPs. Energy Safety's 2026-2028 WMP Guidelines allow a utility to submit a Petition to Amend its approved WMP to align with a Commission decision in a GRC.[92] Energy Safety has approved change order requests during the

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[88] A.21-05-011, Application of SDG&E to Submit Its 2021 RAMP Report (filed May 17, 2021); A.21-05-014, Application of SCG to Submit Its 2021 RAMP Report (filed May 17, 2021).

[89] D.24-12-074 at COLs 145 at 1061-1062 and 307 at 1084.

[90] *Id.*

[91] *See generally* Attachment F (Woldemariam Declaration).

[92] Office of Energy Infrastructure Safety, *Wildfire Mitigation Plan Guidelines* (February 24, 2025), *available at*: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2026-28-wildfire-mitigation-plan-guidelines/.

2023 to 2025 WMP cycle based on updated requirements and targets resulting from the electrical corporation's current rate setting proceeding.[93]

Based on the Decision and the post-test year funding levels, SDG&E recognized that it would need to revise its WMP targets. Accordingly, following the issuance of the Decision in December 2024, SDG&E filed a Petition to Amend with Energy Safety on April 10, 2025. The purpose of SDG&E's Petition to Amend was to revise its 2024 and 2025 WMP initiative targets and 2025 initiative spend to align with the revenue requirement authorized in the Decision.

For 2025, SDG&E's Petition to Amend requested to make changes to the following capital programs:

- Strategic Pole Replacement Program
- Transmission OH Hardening
- Distribution Communications Reliability Improvements
- Drone Assessments
- Lightning Arrester Removal/Replacement
- Connectors, including hotline clamps
- Avian Protection
- Expulsion Fuse Replacement[94]

SDG&E explained the following in its Petition to Amend as to why these changes were needed:

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[93] Office of Energy Infrastructure Safety Decision on PG&E's Change Order Request in relation to its 2023-2025 Base WMP (May 31, 2024) ("2024 PG&E Change Order Decision") at Table 1 at 3-10, *available at*: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2023-wildfire-mitigation-plans/.

[94] SDG&E 2025 Petition to Amend (April 10, 2025) ("Petition to Amend") at 2-3, *available at*: https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58234&shareable=true.

> SDG&E calculated the revenue requirement for its wildfire mitigation program based upon its final GRC Decision. The revenue requirement includes (1) the revenue requirements for covered conductor and strategic undergrounding for each year of the GRC cycle, as explicitly authorized by the CPUC, and (2) the approximate 3 percent for all other wildfire mitigation programs. The table below provides the approved capital expenditures, the calculated authorized revenue requirement, the resulting revenue requirement shortfall, and the associated reduction in capital required to stay within the revenue requirement authorized for the overall wildfire mitigation program.[95]

2024 GRC | WMP (direct $, in millions)	2024	2025	2026	2027	Total
Authorized Capital Expenditures (Capex)	$396	$417	$425	$432	$1,670
Authorized Revenue Requirement	$16	$48	$82	$116	$262
Revenue Requirement necessary to complete Authorized Capex	$16	$64	$131	$199	$410
Revenue Requirement Shortfall	**-**	**($16)**	**($49)**	**($83)**	**($148)**
Reduction to Authorized Capex to align with Authorized Revenue Requirement	-	($199)	($184)	($201)	($584)
Adjusted Capex Target	**$396**	**$218**	**$241**	**$231**	**$1,086**
Actual/Forecasted Capex	**$474**	**$277**	**$153**	**$141**	**$1,045**

SDG&E further explained that in order to "stay within the authorized revenue requirement and because SDG&E exceeded its capital expenditures in 2024, it is necessary to reduce SDG&E's wildfire mitigation spending for 2025, 2026, and 2027."[96]

On July 11, 2025, Energy Safety denied SDG&E's Petition to Amend with respect to four capital-related programs, namely Drone Assessments, Hotline Clamps, Avian Protection and Expulsion Fuse Replacements.[97] Now, SDG&E does not have sufficient funding from the GRC's post-test year mechanism to perform the work that Energy Safety is requiring for these

[95] Petition to Amend at 5.

[96] *Id.*

[97] Office of Energy Infrastructure Safety Decision for SDG&E's 2025 Petition to Amend to its 2023-2025 Base WMP (July 11, 2025), *available at: https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58911&shareable=true*

four WMP capital programs.[98] This is particularly the case with respect to SDG&E's drone inspection program. Due to insufficient authorized funding, SDG&E sought authorization to reduce the number of risk-based drone inspections of infrastructure from 13,500 to 6,500.[99] Due to the denial of that request, SDG&E's drone program is underfunded by approximately $22.0 million for 2025.[100] The total underfunding for the four capital programs denied in the Petition to Amend is $26.8 million in 2025, $14.4 million in 2026, and $4.1 million in 2027.[101] Calculating the revenue requirement for these four capital programs modeled as a budget-based exception would result in a total impact of $0.6 million for 2025, $4.3 million in 2026, and $7.5 million in 2027.[102]

The insufficient post-test year funding for these four WMP programs result in an unfunded mandate, which jeopardizes SDG&E's safety certification and puts the Company at risk for non-compliance and fines under the statutory WMP structure.[103] While SDG&E has a regulatory account where it can record wildfire mitigation plan-related costs (the wildfire mitigation plan memorandum account or WMPMA), this mechanism does not provide current revenue requirement for the additional funding necessary to comply with these mandates.

The Petition's requested two-part attrition mechanism incorporating capital additions using a seven-year average will cover the additional capital costs needed to address Energy Safety's required wildfire mitigation work. Using a budget-based method, SDG&E calculates

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[98] Attachment F (Woldemariam Declaration) at ¶ 13.

[99] *Id.* at ¶ 23.

[100] *Id.*

[101] *Id.* at ¶ 18.

[102] Attachment C (Hancock Declaration) at ¶ 28.

[103] Senate Bill ("SB"), Stats. 2017-2018, Ch. 626 (Cal. 2018);Assembly Bill ("AB"), Stats. 2019-2020, Ch. 79 (Cal. 2019).

the total impacts of these programs would be approximately $12.4 million in capital revenue requirement for 2025, as further described in the Declaration of Melanie Hancock.

b. SoCalGas must defer an authorized PSEP pipeline replacement that is not funded by the PTY mechanism.

As described in the declaration of Bill Kostelnik, the Companies' PSEP program is mandated by the Commission in D.11-06-017 (later codified in Public Utilities Code Sections 957 and 958) and D.14-06-007.[104] The program was initiated after a 30-inch diameter natural gas transmission pipeline ruptured and caught fire in the city of San Bruno, California, and the Commission and legislature determined that "natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety," and that there must be traceable, verifiable records of such compliance.[105] "PSEP is a safety-related program that was included in SoCalGas's 2021 RAMP filing and remains an important control/mitigation of the risk entitled *Incident Related to the High Pressure System (Excluding Dig-in)*."[106]

As the Companies testified, "Since its inception, the four objectives of PSEP have been and continue to be: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments."[107] In the TY 2024 GRC, "a project-specific cost estimate was developed for each pipeline project" using a zero-based approach "[g]iven the size, scope, and complexity of PSEP projects…. However, rather than presenting a forecast that relies on the execution of specific projects in specific years (as was the case in A.17-10-008), SoCalGas is instead requesting authorization to

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[104] Attachment E (Kostelnik Declaration), at ¶ 3.

[105] D.11-06-017 at 18.

[106] Ex. SCG-08 at BGK-17 to BGK-18.

[107] *Id.* at BGK-1.

establish a revenue requirement based on an anticipated level of executable spending from a portfolio of 33 Phase 1B and 2A pipeline projects."[108]

One of the PSEP capital projects included in SoCalGas's forecast that was authorized in the TY 2024 GRC was Supply Line 38-539 Phase 2A Replacement Project.[109] Although the project is a Phase 2A project because it is located in a lower population area, and therefore a lower priority project than those in Phase 1A and 1B, like all PSEP projects, Supply Line 38-539 is required to be tested or replaced "as soon as practicable."[110] This project "will replace approximately 12.57 miles of pipeline."[111] Because of the authorized post-test year mechanism, and SoCalGas's authorization to perform work at an executable level of spending, SoCalGas does not have adequate funds to complete this PSEP replacement project at this time.[112] Without the relief requested herein, SoCalGas will continue to defer this project.[113]

E. Underfunding Capital Costs May Cause Delayed Rate Volatility When The Next GRC Is Implemented

In addition to the deferrals of work that mitigate wildfire and pipeline safety risks to customers noted above, the Decision's post-test year mechanism will hurt customers via rate shock in the long run. This rate shock is due to the Commission's failure to provide sufficient capital costs in revenue requirement, which is contrary to the principles of utility ratemaking that rates should be based on cost causation.[114] The Commission has explained that "a customer, or a

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[108] *Id.* at BGK-19.

[109] *See* D.24-12-074 at 224-226 (removing contingency forecasts only).

[110] Pub. Util. Code § 958.

[111] Ex. SCG-08 at 27. *See also* Ex. SCG-08-WP-S Volume 1-8 at 36-46.

[112] Attachment E (Kostelnik Declaration) at ¶ 12.

[113] *Id.*

[114] D.23-04-040, Attachment A at 1.

customer class, that causes a cost to be incurred by receiving service should pay for the cost of service"[115] for the purpose of "fairly apportion[ing] utility costs to customers and to encourage economically efficient decision making by customers."[116] While the apportionment of costs to customers and customer classes typically occurs in separate cost allocation proceedings,[117] the principle also applies to the GRC Phase 1 in that such "fair apportionment" to "encourage economically efficient decision making by customers" can only occur if the utilities' revenue requirement and rate base are accurate and reflect the full cost to serve customers.

Although customers will be paying lower rates in the short run in the post-test years, it is because they should be, but are not, paying for capital investments underfunded by the Decision and therefore not included in the revenue requirement. However, those underfunded capital investments made by the Companies will be requested for inclusion as part of rate base in the Companies' TY 2028 GRC. Thus, although customers are not currently paying for their share of the capital costs associated with capital improvements made by the Companies in the post-test years (which capital costs the utilities will never recover), the capital assets themselves must still be included in rate base in the TY 2028 GRC to be depreciated over the remainder of their useful life. The result—before any new incremental revenue requirement is approved in the TY 2028 GRC for new capital projects—will be a spike in the revenue requirement (for the "catch-up rate base") representing the approved, but underfunded, capital projects from the prior TY 2024 GRC. This rate volatility is avoidable by correcting the authorized post-test year mechanism for the TY 2024 GRC cycle.

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[115] *Id.*

[116] *Id.*

[117] General Rate Case Phase 2 for electric; Cost Allocation Proceeding for gas.

F. The One-Part Mechanism's Failure to Fund a Reasonable Amount of Capital Costs in the Post-Test Years is Depriving the Companies of a Fair Return on and of Their Capital Investment

The Decision's basic misconception about the factual impact of its adopted post-test year mechanism—namely, that the adopted mechanism allows the Companies to recover their capital expenses and a reasonable return on rate base[118]—has resulted in a violation of the Fourteenth Amendment's takings clause and the underlying principle of regulatory compact. It is well established law that "[r]ates which are not sufficient to yield a reasonable return on the value of the property used *at the time it is being used* to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment."[119] As investor-owned utilities, SoCalGas and SDG&E have dedicated private capital investment to public use under the regulatory compact's framework with the expectation that it would have a return on and of that investment.

Here, the Decision approved certain activities, and found that the approved PTY revenue requirement was allowing the Companies to cover their costs of capital, including a reasonable return on rate base.[120] As almost a year has now passed, it is clear that this is not the case and that the remainder of the post-test years will face increasingly significant shortfalls in the revenue requirement to cover the capital costs necessary to operate in compliance with

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[118] *See* D.24-12-074 at COL 307 at 1084 ("The 3 percent increase in Post-Test Year (PTY) revenue requirement . . .is reasonable because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base. . . .").

[119] *Bluefield Waterworks & Imp. Co. v. Pub. Service Comm. of W. Va.,* 262 U.S. 679, 690 (1923) (emphasis added); *see also Fed. Power Comm. v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (return on equity "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.").

[120] *See* D.24-12-074 at COL 307 at 1084 ("The 3 percent increase in Post-Test Year (PTY) revenue requirement . . .is reasonable because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base. . . .").

obligations to maintain safety and reliability.[121] This is an important and significant policy issue that the Commission should correct, and the Commission would likely make a different determination – and authorize a two-part attrition mechanism that appropriately distinguishes between capital investments and O&M – if it was issuing D.24-12-074 today. This is especially true given the Commission's recent decision to apply a two-part attrition mechanism in SCE's 2025 GRC decision (D.25-09-030), and acknowledgement that the awarded post-test year revenue requirement was "necessary for SCE to continue to provide safe and reliable service to customers beyond the test year, while providing SCE a reasonable opportunity to earn the rate of return as authorized by the Commission in Decision 24-10-008."[122] There is no factually or legally supportable basis for the disparate treatment between the utilities in this regard and no basis for allowing SCE to obtain a reasonable return on their capital investments, while denying SoCalGas and SDG&E the same opportunity.

G. The Record Evidence, the Rate Case Plan, and Sound Policy Recognized in Recent Utility GRCs Support a Two-Part Attrition Mechanism

The Decision finds that "Sempra Utilities has not demonstrated the need for additional funds in the post-test years to account for anticipated growth in capital additions in excess of

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[121] *See, e.g.,* Attachment E (Kostelnik Declaration) at ¶ 12; Attachment F (Woldemariam Declaration) at ¶¶ 18, 22-26; *see also* Tr. Vol. 26 at 4379:8-21 (Maryam Brown) ("These PHMSA requirements have been adopted by the CPUC, and more specifically SED. The CPUC's delegated authority from PHMSA rests on an expectation and an obligation that these federal requirements will be authorized, funded, and enforced. This PD authorizes the work to be done, as it must. But, the money to fund that work in the post-test years is not adequate. This mismatch, between the expectation to continue doing the capital work through the post-test years and the failure to fund that same level of work, sends a potentially dangerous mixed message. From the federal world that I spend time in, the term of art to describe this situation is 'an unfunded mandate.'")

[122] D.25-09-030 at 2; *see also* D.23-11-069 at 707 (acknowledging that while an attrition year mechanism is not guaranteed pursuant to the RCP, PG&E is nonetheless "entitled to an opportunity to earn its authorized rate of return in the post-test years.")

depreciation."[123] This is a misunderstanding of the record evidence. The Companies provided detailed post-test year ratemaking workpapers that demonstrate forecasted capital additions exceed depreciation.[124] Included in the Companies' PTY workpapers were "net plant additions," which are the capital additions in excess of depreciation. This information is further supported by evidence presented in the rebuttal testimony of SoCalGas witness Khai Nguyen[125] and SDG&E witness Melanie Hancock showing increases in capital additions over the 2018 to 2021 time period, which supports the Companies' capital additions-based proposal.[126] SoCalGas also emphasized this issue during oral argument in this proceeding, explaining that the evidence showed that the proposed decision's treatment of capital additions amounted to "an unfunded mandate." [127] Rather than addressing the record evidence, the Decision's post-test year ratemaking section focuses on the escalation of the post-test year revenue requirement rather than evaluating the mechanism itself (one-part vs. two-part mechanism).[128] Choosing the escalation factor or even calculating the level of capital additions, while important, are secondary to establishing an appropriate mechanism[129]

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[123] D.24-12-074 at FOF 438 at 1027.

[124] *See* Ex. SCG-40-WP-2R and Ex. SDG&E-45-WP-R.

[125] Ex. SCG-240-E at KN-8 and Appendix C, KN-C-1 – KN-C-2.

[126] Ex. SDG&E-245 at MEH-10 and Attachment B, MEH-B-2 – MEH-B-7.

[127] Tr. Vol. 26 at 4379:8-21 (Maryam Brown) ("These PHMSA requirements have been adopted by the CPUC, and more specifically SED. The CPUC's delegated authority from PHMSA rests on an expectation and an obligation that these federal requirements will be authorized, funded, and enforced. This PD authorizes the work to be done, as it must. But, the money to fund that work in the post-test years is not adequate. This mismatch, between the expectation to continue doing the capital work through the post-test years and the failure to fund that same level of work, sends a potentially dangerous mixed message. From the federal world that I spend time in, the term of art to describe this situation is 'an unfunded mandate.'")

[128] D.24-12-074, Section 47 at 891-909.

[129] *See, e.g.,* Attachment I, McDermott and Peterson at 21.

For all of the reasons discussed herein, the Decision should be modified to adopt a two-part attrition mechanism based on capital additions. As the Companies testified, the basis for relying on capital additions as the proxy for future capital-related revenue requirement in the post-test years is that "[c]hanges in capital revenue requirement components (authorized returns on rate base, depreciation expense, and taxes) are determined almost entirely by the relationship between capital additions and depreciation. When capital additions exceed depreciation, rate base increases and the related capital revenue requirement components also increase."[130]

Both the RCP and recent Commission decisions[131] acknowledge that because capital costs and O&M expenses affect the revenue requirement differently, it is reasonable to adopt a two-part attrition mechanism that separately escalates O&M expenses and capital-related costs. The United Reform Network ("TURN")/Southern California Generation Coalition ("SCGC") put forth testimony in this proceeding on post-test year ratemaking demonstrating that traditional attrition mechanisms were indeed two parts and based on capital additions:

> The Commission began the attrition mechanism in the early 1980s, a period during which there were extraordinarily high levels of inflation. The traditional attrition mechanism was a two-part mechanism, combining escalation of labor and non-labor O&M expenses with broad indices and a determination of capital-related revenue requirement based on seven years of recorded capital additions.[132]

The Decision relies on Commission decisions from 1980, 1993, and 1999 to authorize a one-part attrition mechanism. In doing so, the Commission also ignores the more recent 2020 Rate Case Plan that acknowledges the need for a two-part mechanism[133] as well as the fact that

[130] *See, e.g.,* Ex. SDG&E-245 at MEH-7.

[131] *See* D.25-09-030 at FOF 842 at 950.

[132] Ex. TURN-SCGC-07 at 4.

[133] D.24-12-074 at 897.

the utility industry has experienced significant transformation over the last 45 years that requires a capital-specific component of the mechanism as a sound policy approach.[134] Utilities have different asset mixes including batteries, microgrids, cloud technology, with increased electric loads and new fuel mixes on the horizon.[135] This evolution and innovation has increased the overall level of utility investment today compared to decades prior, especially in the area of technology which typically has a shorter useful life than more traditional utility assets.[136] For example, smart meters used today have a fifteen-year service life whereas the legacy meters used previously had a service life that was 2-3 times longer, which significantly increases the annual amount of depreciation expense today.[137] A one-part attrition mechanism that simply escalates revenue requirement does not make sense as the utility industry stands today. Any adopted attrition mechanism must account for and appropriately reflect the level of utility investment necessary for the current state of the utility industry, and specifically, the level of capital additions approved in D.24-12-074.

In addition to decisions setting the initial framework and policy for attrition, there is an abundance of recent precedent adopting two-part mechanisms incorporating capital additions. In the Companies' TY 2019 GRC, the Commission adopted a two-part post-test year mechanism incorporating capital additions.[138] Further, PG&E's TY 2023 GRC Decision was issued

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[134] *See* Attachment I, McDermott and Peterson at 12-13. Specifically, "ordinarily separate attrition factors are used for plant additions and operations expenses" and "Capital is also an investment which provides services over several years, often decades, making planning for capital additions less certain in the sense that the cost of replacing existing capital, or the need for new capital investment, may have little to do with the existing cost of capital on the books of the utility."

[135] *See generally* Ex. SDG&E-35-R; Ex. SCG-31-WP-2R.

[136] *See generally id.* (showing that technology driven assets have shorter life spans).

[137] Ex. SDG&E-36-R at DAW-B-2.

[138] D.19-09-051 at 706-707 (finding "that the main factors affecting projected increases in costs anticipated during the PTYs are dissimilar with respect to O&M and capital additions… [and] that the

immediately before this Decision (about 13 months)[139] and SCE's TY 2025 GRC Decision was issued immediately after (9 months).[140] In both instances, this Commission authorized two-part attrition mechanisms with the capital component based on test year capital additions, plus budget-based exceptions.[141] In PG&E's TY 2023 GRC Decision, in addition to a two-part attrition mechanism with a separate capital component, the Commission found it reasonable to adopt specific attrition year budgets for eleven capital projects.[142] SCE's TY 2025 GRC adopts a two-part attrition mechanism, with zero escalation for all non-wildfire related capital additions.[143] The only GRC decision in recent years to not adopt a two-part attrition mechanism is the Companies' TY 2024 GRC Decision in this proceeding.

The failure of D.24-12-074 to adopt a two-part mechanism is a result of the Commission's misunderstanding regarding the different impacts of capital costs and O&M expenses on revenue requirement and belief that the adopted one-part mechanism would permit the Companies to recover their capital costs and rate of return.[144] The Commission's recent precedent in PG&E's and SCE's GRC Decisions and the Rate Case Plan recognize the sound and longstanding policy of adopting two-part attrition mechanisms as reasonable.

PTY mechanism for capital additions should reflect projected capital additions rather than just escalation.")

[139] D.23-11-069, issued on November 17, 2023.

[140] D.25-09-017, issued on September 23, 2025.

[141] D.23-11-069 at FOF 366 at 846 ("[I]t is reasonable to treat expense and capital-related costs differently for purposes of post-test year ratemaking because expense and capital-related costs can affect revenue requirement different, and adopts this practice in this proceeding.").

[142] *Id.* at 715-717.

[143] D.25-09-030 at 846.

[144] *See* D.24-12-074 at COL 307 at 1084 ("The 3 percent increase in Post-Test Year (PTY) revenue requirement . . .is reasonable **because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base**. . . .")(emphasis added).

H. A Two-Part Attrition Mechanism Will Adequately Fund Capital Projects Approved in the TY 2024 GRC

A capital additions-based attrition mechanism would resolve the issues identified in this Petition.[145] The missing revenue resulting from escalating the test year revenue requirement by 3% for the post-test years is remedied by incorporating capital additions in the post-test year revenue requirement calculation.[146] A capital additions-based mechanism more closely reflects the growth in plant in-service and capital-related revenue requirement components and thus is more closely aligned with capital investment needs.[147] A capital additions-based mechanism not only accounts for new capital that is being added to plant in-service during the post-test years, but also the lag in the revenue requirement calculation for assets placed in-service during the test year.[148] The prorated test-year revenue requirement that occurs when capital goes into service throughout the test year needs to be trued-up in the first post-test year to reflect a full year of revenue requirement.[149] The capital additions specific mechanism reflects this true-up and calculates a revenue requirement that incorporates all capital investment in the post-test years.[150]

While the use of capital additions in a two-part attrition mechanism is generally accepted, the years on which to base the calculations of capital additions vary. As explained above, in SCE's 2025 GRC Decision, for all non-wildfire related capital, the Commission adopted a mechanism based on test year capital additions with zero escalation, consistent with SCE's prior

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[145] *See* Attachment C (Hancock Declaration) at ¶¶ 11-15, 29; Attachment B (Nguyen Declaration) at ¶¶ 11-15, 22-23.

[146] *Id.*

[147] *See* Attachment B (Nguyen Declaration) at ¶¶ 5-6; Attachment C (Hancock Declaration) at ¶¶ 5-6.

[148] *Id.; see also* Attachment D (Hom Declaration) at ¶ 9.

[149] *See* Attachment D (Hom Declaration) at ¶ 9.

[150] Attachment B (Nguyen Declaration) at ¶ 6; Attachment C (Hancock Declaration) at ¶ 6.

TY 2021 GRC Decision.[151] PG&E's TY 2023 GRC Decision also adopted an attrition mechanism based on test year capital additions, but applied escalation using S&P Global (formerly Global Insight) Power Planner Service indices.[152] In the Companies' 2019 GRC, the Commission found "a seven-year average using recorded and forecasted capital additions for 2013 to 2019 more reasonably reflects both historical adjustments as well as current and forward-looking additions in light of the evolving changes brought about by the utilities' focus on increasing investment in utility safety and reliability and investments aimed at mitigating safety risk and providing clean and reliable energy."[153] As explained below, the Companies recommend that the Commission adopt a seven-year average of historical and forecasted capital additions.

I. The Companies' Proposed Seven-Year Average of Capital Additions Should Be Adopted For 2025-2027

To remedy the issues caused by a one-part attrition mechanism and the associated negative impacts to the Companies and customers, the Commission should instead adopt a two-part post-test year mechanism.[154] A capital component should be added to the mechanism, and it should be based on capital additions.[155] The Commission should adopt the post-test year mechanism based on a seven-year average of capital additions (2018-2021 recorded and 2022-2024 forecasted). Although the Companies' position used an escalation factor based on Global Insights utility-specific indices, the proper escalation factor is not at issue in this Petition, and the

[151] D.25-09-030 at 846.

[152] D.23-11-069 at 713. IHS Markit's escalation rates referenced in D.23-11-069 are the same as S&P Global Power Planner Service escalation rates.

[153] D.19-09-051 at 708-709.

[154] Attachment B (Nguyen Declaration) at ¶¶ 12-15; Attachment C (Hancock Declaration) at ¶¶ 12-15.

[155] *Id.*

Companies propose to apply the Decision's adopted escalation factor of 3% to the newly added capital component of the attrition mechanism.[156]

The proposed capital additions calculation in this Petition is consistent with the Settlement Agreement in Track 1 between Cal Advocates and the Companies that utilized a seven-year average based on four years of history (2018-2021) and three years of forecast (2022-2024).[157] This approach is supported by the record and is reasonable for the same reasons the Commission found in the Companies' TY 2019 GRC:

> We find that using a seven-year average using recorded and forecasted capital additions for 2013 to 2019 more reasonably reflects both historical adjustments as well as current and forward-looking additions in light of the evolving changes brought about by the utilities' focus on increasing investment in utility safety and reliability and investments aimed at mitigating safety risk and providing clean and reliable energy.
>
> While we agree with Applicants' forward-looking focus and increased programs on improving safety, risk mitigation, grid modernization, and support of California's clean energy and environmental initiatives, it is not certain at this point in time at what level these activities will continue to increase and whether or not and at what point additional spending efficiently matches the amount of risk reduction and increased safety. Thus, we find that it is also important to incorporate historical adjustments. A seven-year average provides a more effective normalization of capital additions.[158]

Thus, the Commission correctly found in the TY 2019 GRC Decision that a seven-year average of capital additions using historical and forecasted data would provide the Companies with sufficient revenue to invest in capital over the GRC cycle. In this proceeding, the

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[156] *See* Ex. SCG-40-2R-E at KN-4-5; Ex. SDG&E-45-R-E at MEH-4 – MEH-5.

[157] *Compare* Attachment B (Nguyen Declaration) at ¶¶ 11-12 *and* Attachment C (Hancock Declaration) at ¶¶ 11-12 *with* Joint Motion of SoCalGas, SDG&E, TURN, Public Advocates Office, and The Small Business Utility Advocates for Adoption of Settlement Agreement (October 24, 2023) at Attachment A.

[158] D.19-09-051 at 708-709 (internal footnotes omitted).

Companies testified that they expect their respective capital programs to "continue to focus on investments necessary to build and maintain safe and reliable infrastructure and to mitigate safety risks identified in its 2021 RAMP Report…Consequently, the level of estimated capital expenditures leading up to and including TY 2024 are part of an ongoing investment effort, which will continue beyond the test year period. Therefore, the PTY attrition mechanism should reflect the anticipated growth in capital additions in excess of depreciation in the PTY period."[159]

Looking at the record in this proceeding, all intervenors submitting testimony on a post-test year mechanism, except one, argued for a two-part attrition mechanism with the capital component incorporating capital additions.[160] For instance, TURN/SCGC and Federal Executive Agencies ("FEA") recommended attrition mechanisms based on a seven-year average, although based on recorded (2015-2021) capital additions.[161] The Companies disagreed with the proposal to use 2015 through 2021 because it undervalued the Companies' post-test year capital needs by ignoring the more recent data from 2022 to 2024, but importantly, key intervenors either proposed or agreed to settle on a seven year average for a post-test year capital mechanism.[162]

If the Commission does not adopt a seven-year average of capital additions in this Petition, in the alternative, the Commission could adopt the Companies' requested five-year average of capital additions, for the reasons stated in testimony, or the mechanism adopted in

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[159] Ex. SCG-40-2R-E at KN-3; Also see Ex. SDG&E-45-R at MEH-3. Footnotes omitted.

[160] *See* Ex. TURN-SCGC-07 at 11; Ex. FEA-01 at 42-43; Ex. CA-20 at 18; *see also* Joint Motion of SoCalGas, SDG&E, TURN, Public Advocates Office, and The Small Business Utility Advocates for Adoption of Settlement Agreement (October 24, 2023) at Attachment A.

[161] *See* Ex. TURN-SCGC-07 at 8-12. TURN/SCGC proposed capital escalation using CPI-U. *See* Ex. FEA-01 at 42-43. FEA did not take a position on capital escalation indices.

[162] *See* Joint Motion of SoCalGas, SDG&E, TURN, Public Advocates Office, and The Small Business Utility Advocates for Adoption of Settlement Agreement (October 24, 2023) at Attachment A; Ex. TURN-SCGC-07 at 11; Ex. FEA-01 at 42-43; SDG&E-245 at MEH-10; SCG-240-E at KN-7.

SCE's TY 2025 GRC of test year (2024) capital additions with zero escalation. The Companies proposed a five-year average of capital additions (2020-2021 recorded and 2022-2024 forecasted) escalated by S&P Global Power Planner Service[163] "as it takes into account a broader range of data and can provide a more accurate representation of historical and long-term trends."[164] The Companies also stated that five-year average "best captures the utility investment profile and operating initiatives of the current utility environment, which has evolved in the past few years with the risk-informed GRC framework."[165]

Table 4 below provides the post-test year revenue requirement results of the seven-year average of capital additions.

Table 4. Proposed Revenue Requirement Adjustments[166]

Mechanism	Revenue Requirement *($ in millions)*	SoCalGas			SDG&E		
		2025	2026	2027	2025	2026	2027
Authorized	Total	$3,996	$4,112	$4,232	$2,846	$2,965	$3,086
	Increase (a)	$190	$116	$120	$147	$119	$121
Seven-Year Average of Capital Additions (2018-2024)	Total	$4,082	$4,321	$4,550	$2,901	$3,107	$3,308
	Increase (b)	$277	$239	$229	$202	$206	$201
	Incremental Increase from Authorized (b)-(a)	**$86 2.3%**	**$122 2.9%**	**$109 2.4%**	**$55 2.1%**	**$87 2.9%**	**$79 2.4%**

As illustrated in Table 4 above, compared to the Decision's already authorized post-test year amounts, the seven-year average of capital additions would result in year-over-year increases for 2025, 2026, and 2027 of 2.3%, 2.9%, 2.4% for SoCalGas, and 2.1%, 2.9%, 2.4%

163 Ex. SCG-401/SDG&E-401 at 7-8.

164 Companies' Opening Brief (filed August 14, 2023) at 841.

165 Ex. SCG-240-E at KN-8.

166 Totals may include rounding differences.

for SDG&E.[167] The proposed seven-year average of capital additions allows for recovery of capital costs with the lowest revenue requirement increase compared to the alternatives of a five-year average of capital additions or test year capital additions with zero escalation (SCE's TY 2025 GRC Decision outcome).[168]

In addition to adopting a two-part attrition mechanism for purposes of reflecting sufficient capital-related costs, the Commission should also adopt the requested relief in this Petition because it will avoid the associated rate spike resulting from truing up the capital-related revenue requirement for actual rate base during the Companies' TY 2028 GRC implementation. As discussed in the declarations of Michael W. Foster and Rachelle R. Baez, the Companies estimate that a typical residential, non-CARE customer bill will increase as follows:

- SoCalGas: $1.09 (1.5%) in 2025, $2.65 (3.6%) in 2026 and $4.03 (5.4%) in 2027
- SDG&E Gas: $0.54 (0.8%) in 2025, $0.86 (1.3%) in 2026 and $0.87 (1.3%) in 2027
- SDG&E Electric: $1.37 (0.8%) in 2025, $3.23 (1.8%) in 2026 and $5.11 (2.8%) in 2027[169]

These modest bill impacts will result in significant value to customers by allowing the Companies to fund critical and necessary work. Thus, the Companies proposal offers a balanced approach.

[167] Attachment B (Nguyen Declaration) at ¶ 12; Attachment C (Hancock Declaration) at ¶ 12.

[168] Attachment B (Nguyen Declaration) at ¶¶ 11, 19, 24; Attachment C (Hancock Declaration) at ¶¶ 11, 19, 24.

[169] Attachment G (Foster Declaration) ¶ 6-7; Attachment H (Baez/Foster Declaration) at ¶¶ 10-11. The bill impacts are based on current effective rates and models as of October 1, 2025 and reflect as if the requested relief in the PFM were implemented timely at the beginning of each year. The actual rate and bill impacts will differ based upon the models in effect upon implementation and the amortization period to account for the delay in the cost recovery.

J. Implementation of the Requested Modification

As part of the TY 2024 GRC, the Commission issued D.23-05-012 granting SoCalGas and SDG&E each authority to establish a GRC memorandum account ("GRCMA"). The GRCMA records the "shortfall or overcollection resulting from the difference between the revenue requirement and corresponding rates in effect on January 1, 2024 for utility service and the final revenue requirement and corresponding rates adopted by the Commission in a decision for Application (A.) 22-05-015,"[170] the Companies' TY 2024 GRC proceeding. The Companies' respective GRCMAs remain open and can be utilized for implementation of the relief requested in this Petition.

Should the Commission grant the requested relief herein, the Companies can record the difference between the Petition's final decision and D.24-12-074 in the GRCMAs until the date new rates are implemented. The Decision found it "reasonable to require SoCalGas and SDG&E to amortize the balance recorded in each utility's respective GRCMA in rates over 18 months from the date the new tariffs are implemented."[171] Amortization of the current balances in the GRCMAs will be complete on July 31, 2026. The end of the GRCMAs amortization related to the 2024 test year will result in a rate decrease. Rather than rates decreasing due to the roll off of the GRCMA balances from the Decision just to have rates increase because of this Petition, the Companies request the Commission consider rate smoothing by commencing implementation of any balance in the GRCMAs resulting from this Petition on August 1, 2026 and amortize those

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[170] SoCalGas General Rate Case Memorandum Account 2024 (GRCMA2024) Preliminary Statement, https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=566. Also see SDG&E's GRCMA2024 Preliminary Statement for electric (https://tariffsprd.sdge.com/view/tariff/?utilId=SDGE&bookId=ELEC&tarfKey=942) and gas (https://tariffsprd.sdge.com/view/tariff/?utilId=SDGE&bookId=GAS&tarfKey=943).

[171] D.24-12-074 at 4.

amounts over a minimum 12-month period.[172] This would help to provide rate stability for customers while permitting the Companies to timely collect revenues.

In addition to amortizing balances, to the extent a decision is issued on this Petition prior to when the January 1 attrition year rate changes occur, the Companies request to include the modified attrition year revenue requirement in rates through the currently adopted processes.[173] As stated in Ordering Paragraph 9 of the Decision, SoCalGas will include the update for its post-test year revenue requirements via the annual true-up Tier 2 Advice Letter by October 15 of the year prior to the January 1 rate change.[174] For SDG&E and consistent with Ordering Paragraph 8 of the Decision, post-test year revenue requirements will be updated by "filing a Tier 2 Advice Letter by November 15 of the year prior to the January 1 rate change with the initial estimated revenue requirement amount and subsequently update the forecast with the actual amount that was authorized in a separate Tier 1 Advice Letter to be filed by December 31."[175] Any partial year rate change may be implemented at the next scheduled rate change or as approved by Energy Division.[176]

VI. PROPOSED MODIFICATIONS TO PROVIDE THE REQUESTED RELIEF

Rule 16.4 (b) requires that a petition for modification "propose specific wording to carry out all requested modifications to the decision." SoCalGas's and SDG&E's proposed modifications to the D.24-12-074 are set forth in Attachment A in redline.

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[172] Attachment H (Baez/Foster Declaration) at ¶ 6; Attachment G (Foster Declaration) at ¶ 5.

[173] Attachment H (Baez/Foster Declaration) at ¶ 5; Attachment G (Foster Declaration) at ¶ 4.

[174] D.24-12-074, Ordering Paragraph ("OP") 9 at 1088.

[175] *Id.*, OP 8 at 1088.

[176] Attachment H (Baez/Foster Declaration) at ¶ 6; Attachment G (Foster Declaration) at ¶ 5.

VII. CONCLUSION

For the reasons set forth above, SoCalGas and SDG&E respectfully request modification of D.24-12-074 to adopt a two-part post-test year mechanism with the capital component incorporating a seven-year average of capital additions and a 3% escalation factor. A modification of the Decision to adopt a separate PTY mechanism for capital will adequately fund approved capital projects and will permit the Companies to cover their operating expenses, capital costs, and a reasonable return on its rate base as was originally intended by the Decision.

Respectfully submitted,

/s/ Rebecca D. Hansson

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San Diego Gas & Electric Company

December 17, 2025

ATTACHMENT A

Proposed text deletions are in strikethrough (~~deletion~~)
Proposed text additions are in red (addition)

Section 47

p.895-96 The decision adopts a two-part PTY ratemaking mechanism that separately escalates O&M expenses and capital-related costs. Specifically, we authorize an ~~base margin revenue~~ ~~(~~O&M ~~and capital~~ revenue requirement~~)~~ increase of 3 percent each year for 2025, 2026, and 2027 plus capital additions, including certain wildfire mitigations, including undergrounding and covered conductor.

p.898 ~~However, Sempra has not demonstrated how an attrition increase is necessary to account for capital additions in excess of depreciation in the PTY period in terms of changes in capital revenue requirement components (authorized returns on rate base, depreciation expense, and taxes).~~

p.901 Since O&M expenses and capital costs affect the revenue requirement differently, it is reasonable to adopt a two-part PTY ratemaking mechanism that separately escalates O&M expenses and capital-related costs. We adopt Cal Advocates' and TURN-SCGC's recommendations with a modification to increase the PTY GRC ~~base margin revenue~~ ~~(~~O&M ~~and capital~~ revenue requirement~~)~~ by 3 percent each year for years 2025, 2026, and 2027. For capital, we adopt a seven-year average using recorded and forecasted capital additions for 2018 to 2024 escalated by 3 percent plus additional increases for PTY wildfire mitigation capital exceptions. This approach allows Sempra to fund incremental capital additions, including for wildfire mitigation programs that are important for infrastructure safety. The seven-year average of capital additions is consistent with D.19-09-051 where the Commission similarly recognized the need to reasonably reflect historical and forward-looking additions in the post-test years.[1] To provide a mechanism for funding Gas Integrity Management Programs in the post-test years, the Commission authorizes SoCalGas and SDG&E to record costs in the gas integrity memorandum accounts for TIMP, DIMP, and SIMP in amounts prudently incurred to comply with regulatory standards.

p.901-02 Accordingly, the Commission adopts Cal Advocates' recommendation to increase the PTY GRC base revenue by ~~no more than~~ 3 percent each year for 2025, 2026, and 2027 as escalation-related increases for O&M, a seven-year average (2018-2024) of capital additions escalated by 3 percent, plus additional increases for PTY wildfire mitigation capital exceptions.

[1] D.19-09-051 at 708-709.

p.907 For the remaining capital budget categories within WMVM, their post-Test Year authorizations are included as part of the ~~3%~~two-part PTY ratemaking mechanism.

p.909 Sempra shall file a PTY Ratemaking adjustment advice letter for the upcoming attrition years 2025, 2026, and 2027. ~~The attrition year revenue requirement and percentage adjustments for each attrition year shall be based on the authorized Test Year 2024 revenue requirement.~~ Sempra shall adjust its ~~base margin~~O&M revenue requirement by 3 percent each year for 2025, 2026, and 2027, capital revenue requirement using the 7-year average of capital additions adjusted by 3 percent, plus the wildfire mitigation PTY capital exception. In addition, Sempra shall implement any changes resulting from changes to its authorized Cost of Capital for 2025, 2026, and 2027.

Findings of Fact

NEW Since O&M expenses and capital costs affect the revenue requirement differently, it is reasonable to adopt a two-part post-test year ratemaking mechanism that separately escalates O&M expenses and capital-related costs.

FOF 437 Sempra Utilities has ~~insufficiently~~ demonstrated the need for a general Post-Test Year capital attrition mechanism.

FOF 438 Sempra Utilities has ~~not~~ demonstrated the need for additional funds in the post-test years to account for anticipated growth in capital additions in excess of depreciation.

Conclusions of Law

COL 307 The 3 percent increase in Post-Test Year (PTY) O&M revenue requirement and as well as a 3 percent escalation on a seven-year average of capital additions, including a capital exception for SDG&E's wildfire mitigation for Grid Design and System Hardening costs and various memorandum accounts for Gas Integrity Management Programs is reasonable because it allows Sempra Utilities to cover its operating expenses, capital costs, and a reasonable return on its rate base. All other PTY capital exceptions are unreasonable and should be denied.

COL 310 Sempra Utilities (Sempra) should file a Post-Test Year Ratemaking adjustment advice letter for attrition years 2025, 2026, and 2027. The attrition year revenue requirement and percentage adjustments for each attrition year should be based on the authorized Test Year 2024 revenue requirement for O&M and a seven-year average of capital additions. Sempra should use 3 percent escalation rates to adjust its ~~base margin~~ O&M revenue requirement and capital additions for the upcoming attrition years.

ATTACHMENT B

KHAI NGUYEN DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	A.22-05-015 (Filed May 16, 2022)
And Related Matter.	A.22-05-016 (Filed May 16, 2022)

DECLARATION OF KHAI NGUYEN ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY IN SUPPORT OF THE PETITION FOR MODIFICATION OF D.24-12-074

I, Khai Nguyen, declare that:

1. I am currently employed by Southern California Gas Company ("SoCalGas") as the Financial & Strategic Planning Manager. My current responsibilities include the financial planning and analysis functions at SoCalGas. I sponsored testimony on behalf of SoCalGas in Track 1 of the above-captioned Test Year ("TY") 2024 General Rate Case ("GRC") proceeding, supporting Post-Test Year Ratemaking.[1]

2. The purpose of my declaration is to provide factual support for the Petition for Modification ("Petition" or "PFM") of Decision ("D.") 24-12-074, issued on December 23, 2024 (hereinafter referred to as the "2024 GRC Decision"), specifically for SoCalGas's request to modify the post-test year mechanism authorized in the 2024 GRC Decision.

The 2024 GRC Decision Approved a One-part Post-Test Year Mechanism for 2025, 2026, and 2027

3. The 2024 GRC Decision authorized a one-part post-test year mechanism that escalates the 2024 O&M and capital revenue requirement by about 3%.

[1] Exhibits ("Ex.") SCG-40-2R-E, SCG-40-WP-2R-E, SCG-40-S, SCG-240-E.

4. The 2024 GRC Decision authorized test year and post-test year revenue requirements as shown below in Table 1.

Table 1. SoCalGas Authorized Revenue Requirement

$ in millions	2024	2025	2026	2027
Revenue Requirement	$3,806	$3,996	$4,112	$4,232
Increase ($)	$324	$190	$116	$120
Increase (%)	9.3%	5.0%	2.9%	2.9%

5. Unlike expenses that can generally be escalated using indices reflecting inflation, capital cost growth is much more complex and is driven by plant and rate base growth, not just cost escalation.[2]

6. As described in my direct testimony, growth in capital-related costs (depreciation, taxes and authorized return) is primarily determined by the relationship between capital additions and depreciation. Capital additions in excess of depreciation drive rate base growth and therefore a growth in capital-related costs.[3] A capital additions-based mechanism accounts for new capital that is being added to plant in-service during the post-test years and takes into consideration the revenue needed to service projects that were placed into service during the test year.

A Two-part Post-Test Year Mechanism for 2025, 2026, and 2027 Should Be Adopted

7. In my direct testimony, I proposed a two-part post-test year mechanism that separately escalates O&M and capital. A two-part mechanism is consistent with most parties' testimony that addressed post-test year ratemaking.[4]

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[2] Ex. SCG-240-E at KN-7.
[3] Ex. SCG-40-2R-E at KN-7.
[4] Ex. TURN-SCGC-07.

8. For the capital component of the two-part mechanism, I proposed that the Commission adopt a methodology that uses a five-year average of capital additions to calculate the revenue requirements for 2025, 2026, and 2027. The five years I proposed were 2020-2021 based on recorded capital additions and 2022-2024 based on forecasted capital additions.[5]

9. Cal Advocates initially proposed a one-part post-test year mechanism that escalated the 2024 O&M and capital revenue requirement. I rebutted the use of a one-part mechanism explaining the following:

> SoCalGas disagrees with Cal Advocates methodology of escalating test year revenue requirement using CPI instead of using of an escalated multi-year average of capital additions as a proxy for post-test year capital additions. Using a 5-year average (2020-2021 recorded and 2022-2024 forecasted) is more reliable than escalating the test year, as it takes into account a broader range of data and can provide more accurate representation of historical and long-term trends.[6]

10. Cal Advocates, SoCalGas, and SDG&E reached a settlement on post-test year ratemaking that included a two-part post-test year mechanism that separately escalated O&M and capital. The capital component with the settled mechanism was a seven-year average of capital additions using 2018-2021 recorded data and 2022-2024 forecasted data. The settlement's seven-year average methodology is consistent with the Commission's adopted post-test year mechanism for SoCalGas and SDG&E in the TY 2019 GRC cycle.

11. Table 2 below shows the post-test year revenue requirements calculated under a two-part post-test year mechanism, using the methodology SoCalGas proposed and the methodology under the settlement with Cal Advocates. The results in Table 2 include the O&M component of the mechanism consistent with the 2024 GRC Decision.

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[5] Ex. SCG-40-2R-E at KN-6 to KN-8.
[6] Ex. SCG-240-E at KN-8.

Table 2. SoCalGas Revenue Requirement Using a Two-Part Mechanism[7,8]

$ in millions	2024	2025	2026	2027
Five-year Average Capital Additions (2020-2024)	$3,806	$4,086	$4,336	$4,575
Seven-year Capital Additions (2018-2024)	$3,806	$4,082	$4,321	$4,550

12. The 2024 GRC Decision authorized a post-test year revenue requirement for 2025-2027. Table 3 below provides the revenue requirements for a two-part attrition mechanism calculated using the five-year and seven-year averages that are in excess of the levels authorized in the 2024 GRC Decision.

Table 3. SoCalGas Incremental Revenue Requirement Using Two-Part Mechanism

$ in millions	2024	2025	2026	2027
Authorized				
Total Revenue Requirement	$3,806	$3,996	$4,112	$4,232
Increase (a)	$0	$190	$116	$120
Five-Year Average of Capital Additions (2020-2024)				
Total Revenue Requirement	$3,806	$4,086	$4,336	$4,575
Increase (b)	$0	$281	$249	$239
Incremental Increase from Authorized (b)-(a)	**$0**	**$90** **2.4%**	**$133** **3.2%**	**$120** **2.6%**
Seven-Year Average of Capital Additions (2018-2024)				
Total Revenue Requirement	$3,806	$4,082	$4,321	$4,550
Increase (c)	$0	$277	$239	$229
Incremental Increase from Authorized (c)-(a)	**$0**	**$86** **2.3%**	**$122** **2.9%**	**$109** **2.4%**

13. If granted, the five-year average of capital additions would result in incremental revenue requirement of $90 million for 2025, $133 million for 2026, and $120 million for 2027.

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[7] Both scenarios reflect the modified 2023 Cost of Capital, effective in 2025 per D.24-10-008, and a one-time tax benefit adjustment in 2025 per D.24-12-074.
[8] Totals may include rounding differences.

14. The seven-year average of capital additions, if granted, would result in the incremental revenue requirements of $86 million for 2025, $122 million for 2026, and $109 million for 2027.

15. The incremental revenue requirements shown in Table 3 above, if adopted, will allow SoCalGas to continue to invest in its system during the TY 2024 GRC cycle while also providing SoCalGas with a fair opportunity to earn its authorized rate of return.

A Two-part Post-Test Year Mechanism Was Approved for Southern California Edison Company's 2025 Test Year General Rate Case

16. D.25-09-030 was issued September 23, 2025 in Southern California Edison Company's ("SCE") TY 2025 GRC (hereinafter referred to as the "SCE 2025 GRC Decision").

17. The SCE 2025 GRC Decision authorized a two-part post-test year mechanism that separately escalates O&M and capital.

18. In the SCE 2025 GRC Decision, post-test year capital was calculated based on test year capital additions with zero escalation.

19. Table 4 below shows what the post-test year revenue requirements would be for SoCalGas calculated under a two-part post-test year mechanism, using the methodology authorized in the SCE 2025 GRC Decision. The results in Table 4 include the O&M component of the mechanism consistent with the 2024 GRC Decision.

Table 4. SoCalGas Revenue Requirement Using SCE's Two-Part Attrition Methodology

$ in millions	2024	2025	2026	2027
TY Capital Additions 2024	$3,806	$4,095	$4,364	$4,615

20. The 2024 GRC Decision authorized a post-test year revenue requirement for 2025-2027. Table 5 below provides the incremental revenue requirements when applying SCE's 2025 GRC Decision (test year capital additions with zero escalation) to SoCalGas.

Table 5. SoCalGas Incremental Revenue Requirement Using SCE Attrition Methodology[9]

$ in millions	**2024**	**2025**	**2026**	**2027**
Authorized				
Total Revenue Requirement	$3,806	$3,996	$4,112	$4,232
Increase (a)	$0	$190	$116	$120
TY Capital Additions 2024				
Total Revenue Requirement	$3,806	$4,095	$4,364	$4,615
Increase (b)	$0	$290	$269	$251
Incremental Increase from Authorized (b)-(a)	**$0**	**$99** **2.6%**	**$152** **3.6%**	**$131** **2.8%**

21. Using the methodology approved for SCE, the incremental revenue requirement for SoCalGas is $99 million for 2025, $152 million for 2026 and $131 million for 2027.

The Commission Should Grant a Seven-Year Average of Capital Additions as the Capital Component of a Two-Part Attrition Mechanism

22. The Commission should grant a modification of the post-test year mechanism from the adopted one-part mechanism to a two-part mechanism. To calculate the capital component, the Commission should use the seven-year average of capital additions methodology based on 2018-2021 recorded information and 2022-2024 forecasts authorized in the 2024 GRC Decision.

23. Using this seven-year average methodology is reasonable for the same reasons the Commission found reasonable in the 2019 GRC Decision:

> We find that using a seven-year average using recorded and forecasted capital additions for 2013 to 2019 more reasonably reflects both historical adjustments as well as current and forward-looking additions in light of the evolving changes brought about by the utilities' focus on increasing investment in utility safety and reliability and investments aimed at mitigating safety risk and providing clean and reliable energy.
>
> While we agree with Applicants' forward-looking focus and increased programs on improving safety, risk mitigation, grid modernization, and support of California's clean energy and environmental initiatives, it is not certain at this

[9] Totals may include rounding differences.

> point in time at what level these activities will continue to increase and whether or not and at what point additional spending efficiently matches the amount of risk reduction and increased safety. Thus, we find that it is also important to incorporate historical adjustments. A seven-year average provides a more effective normalization of capital additions.[10]

24. Additionally, comparing the resulting revenue requirement increases in Table 3 and Table 5 demonstrate that the seven-year average is the most modest option discussed herein.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 17th day of December 2025, at Los Angeles, California.

/s/ Khai Nguyen
Khai Nguyen

[10] D.19-09-051 at 708-709 (internal footnotes omitted).

ATTACHMENT B.1

SOCALGAS WORKPAPERS TO DECLARATION OF KHAI NGUYEN ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

SoCalGas PTY		7-Year Avg Capital Additions				FD				FD less 7-Year Avg Scenario			
Line No.	**Description ($ in millions)**	**TY - 2024**	**PTY – 2025**	**PTY – 2026**	**PTY – 2027**	**TY - 2024**	**PTY – 2025**	**PTY – 2026**	**PTY – 2027**	**TY - 2024**	**PTY – 2025**	**PTY – 2026**	**PTY – 2027**
1	O&M Related Costs	1,591.9	1,639.7	1,688.9	1,739.5	1,591.9	1,639.7	1,688.8	1,739.5	-	0.0	0.0	0.0
2	Capital Related Costs (Depreciation, Taxes, Return)	2,117.8	2,302.3	2,471.8	2,644.8	2,117.8	2,181.3	2,246.8	2,314.2	-	121.0	225.1	330.6
3	PTY Capital Exceptions Related Cost	-	-	-	-	-	-	-	-	-	-	-	-
4	Base Margin excluding FF&U (L1 + L2 + L3)	3,709.7	3,942.0	4,160.7	4,384.3	3,709.7	3,821.0	3,935.6	4,053.7	-	121.0	225.1	330.6
5	FF&U	57.8	58.5	59.3	60.1	57.8	59.5	61.3	63.2	-	(1.0)	(2.0)	(3.1)
6	Total Base Margin (L4 + L5)	3,767.5	4,000.6	4,220.0	4,444.4	3,767.5	3,880.5	3,996.9	4,116.8	-	120.0	223.1	327.5
7	Miscellaneous Revenues	115.4	115.4	115.4	115.4	115.4	115.4	115.4	115.4	-	(0.0)	(0.0)	(0.0)
8	**Total Revenue Requirement (L6 + L7)**	**3,882.9**	**4,115.9**	**4,335.4**	**4,559.8**	**3,882.9**	**3,995.9**	**4,112.3**	**4,232.2**	**-**	**120.0**	**223.0**	**327.5**
9	2023 Tax Benefit including FF&U	(77.3)				(77.3)	-	-	-	-	-	-	-
10	COC Adjustment (incl FF&U)	-	(36.3)	(38.9)	(41.5)	-	-	-	-	-	(36.3)	(38.9)	(41.5)
11	FF&U Adjustment	-	2.6	24.6	31.7	-	-	-	-	-	2.6	24.6	31.7
12	**Adjusted Total Revenue Requirement (L8 + L9)**	**3,805.6**	**4,082.2**	**4,321.1**	**4,550.0**	**3,805.6**	**3,995.9**	**4,112.3**	**4,232.2**	**-**	**86.3**	**208.8**	**317.8**
13	Revenue Requirement Increase $		276.6	238.9	228.9		190.3	116.4	119.9		86.3	122.4	109.0
14	Revenue Requirement Increase %		*7.27%*	*5.85%*	*5.30%*		*5.00%*	*2.91%*	*2.92%*		*2.27%*	*2.94%*	*2.38%*

ATTACHMENT C

MELANIE E. HANCOCK DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	A.22-05-015 (Filed May 16, 2022)
And Related Matter.	A.22-05-016 (Filed May 16, 2022)

DECLARATION OF MELANIE E. HANCOCK ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.24-12-074

I, Melanie E. Hancock, declare that:

1. I am currently employed by San Diego Gas & Electric Company ("SDG&E") as a Financial & Strategic Planning Manager. My current responsibilities include leading the development of financial plans and outlooks, overseeing company-wide capital and O&M planning, and advancing strategic planning initiatives across the organization. I sponsored testimony on behalf of SDG&E in Track 1 of the above-captioned Test Year ("TY") 2024 General Rate Case ("GRC") proceeding, supporting Post-Test Year Ratemaking.[1]

2. The purpose of my declaration is to provide factual support for the Petition for Modification ("Petition" or "PFM") of Decision ("D.") 24-12-074, issued on December 23, 2024 (hereinafter referred to as the "2024 GRC Decision"), specifically for SDG&E's request to modify the post-test year mechanism authorized in the 2024 GRC Decision.

The 2024 GRC Decision Approved a One-part Post-Test Year Mechanism for 2025, 2026, and 2027.

3. The 2024 GRC Decision authorized a one-part post-test year mechanism that escalates the 2024 O&M and capital revenue requirement by about 3%.

[1] Exhibits ("Ex.") SDG&E-45-R, SDG&E-45-WP-R, SDG&E-45-S, SDG&E-245.

4. The 2024 GRC Decision authorized test year and post-test year revenue requirements as shown below in Table 1.

Table 1. SDG&E Authorized Revenue Requirement

$ in millions	**2024**	**2025**	**2026**	**2027**
Revenue Requirement	$2,699	$2,846	$2,965	$3,086
Increase ($)	$189	$147	$119	$121
Increase (%)	7.5%	5.5%	4.2%	4.1%

5. Unlike expenses that can generally be escalated using indices reflecting inflation, capital cost growth is much more complex and is driven by plant and rate base growth, not just cost escalation.[2]

6. As described in my direct testimony, growth in capital-related costs (depreciation, taxes, and authorized return) is primarily determined by the relationship between capital additions and depreciation. Capital additions in excess of depreciation drive rate base growth and therefore a growth in capital-related costs.[3] A capital additions-based mechanism accounts for new capital that is being added to plant in-service during the post-test years and takes into consideration the revenue needed to service projects that were placed into service during the test year.

A Two-part Post-Test Year Mechanism for 2025, 2026, and 2027 Should Be Adopted

7. In my direct testimony, I proposed a two-part post-test year mechanism that separately escalates O&M and capital. A two-part mechanism is consistent with most parties' testimony that addressed post-test year ratemaking.[4]

8. For the capital component of the two-part mechanism, I proposed that the Commission adopt a methodology that uses a five-year average of capital additions to calculate

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[2] Ex. SDG&E-245 at MEH-7.
[3] Ex. SDG&E-45-R at MEH-7.
[4] Ex. FEA-01.

the revenue requirements for 2025, 2026, and 2027. The five years I proposed were 2020-2021 based on recorded capital additions and 2022-2024 based on forecasted capital additions.[5]

9. Cal Advocates initially proposed a one-part post-test year mechanism that escalated the 2024 O&M and capital revenue requirement. I rebutted the use of a one-part mechanism explaining the following:

> Furthermore, an attrition adjustment based on CPI will not reflect revenue requirement increases from plant additions in excess of depreciation (rate base growth) and cost escalation SDG&E will face in the attrition years. Changes in capital revenue requirement components (authorized returns on rate base, depreciation expense, and taxes) are determined almost entirely by the relationship between capital additions and depreciation. When capital additions exceed depreciation, rate base increases and the related capital revenue requirement components also increase. These increases are unrelated to inflation, and rate base growth has no correlation to CPI.[6]

10. Cal Advocates, SoCalGas, and SDG&E reached a settlement on post-test year ratemaking that included a two-part post-test year mechanism that separately escalated O&M and capital. The capital component with the settled mechanism was a seven-year average of capital additions using 2018-2021 recorded data and 2022-2024 forecasted data. The settlement's seven-year average methodology is consistent with the Commission's adopted post-test year mechanism for SoCalGas and SDG&E in the TY 2019 GRC cycle.[7]

11. Table 2 below shows the post-test year revenue requirements calculated under a two-part post-test year mechanism, using the methodology SDG&E proposed and the methodology under the settlement with Cal Advocates. The results in Table 2 include the O&M component of the mechanism and the budget-based capital exception for Covered Conductor and Strategic Undergrounding, consistent with the 2024 GRC Decision.

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[5] Ex. SDG&E-45-R at MEH-6 - MEH-8.
[6] Ex. SDG&E-245 at MEH-7.
[7] *See* D.19-09-051 at 708-709 (internal footnotes omitted).

Table 2. SDG&E Revenue Requirement Using a Two-Part Mechanism

$ in millions	2024	2025	2026	2027
Five-year Average Capital Additions (2020-2024)	$2,699	$2,911	$3,120	$3,324
Seven-year Average Capital Additions (2018-2024)	$2,699	$2,901	$3,107	$3,308

12. The 2024 GRC Decision authorized a post-test revenue requirement for 2025-2027. Table 3 below provides the revenue requirement for a two-part attrition mechanism calculated using the five-year and seven-year averages that are in excess of the levels authorized in the 2024 GRC Decision.

Table 3. SDG&E Incremental Revenue Requirement Using Two-Part Mechanism

$ in millions	2024	2025	2026	2027
Authorized				
Total Revenue Requirement	$2,699	$2,846	$2,965	$3,086
Increase (a)	$0	$147	$119	$121
Five-Year Average of Capital Additions (2020-2024)				
Total Revenue Requirement	$2,699	$2,911	$3,120	$3,324
Increase (b)		$213	$209	$204
Incremental Increase from Authorized (b)-(a)[8]	$0	$66 2.4%	$90 3.0%	$82 2.4%
Seven-Year Average of Capital Additions (2018-2024)				
Total Revenue Requirement	$2,699	$2,901	$3,107	$3,308
Increase (c)		$202	$206	$201
Incremental Increase from Authorized (c)-(a)[9]	$0	$55 2.1%	$87 2.9%	$79 2.4%

13. If granted, the five-year average of capital additions would result in incremental revenue requirements of $66 million for 2025, $90 million for 2026, and $82 million for 2027.

14. If granted, the seven-year average of capital additions would result in the incremental revenue requirements of $55 million for 2025, $87 million for 2026, and $79 million for 2027.

[8] Represents the differential between the year-over-year increases.
[9] *Id.*

15. The incremental revenue requirements shown in Table 3 above, if adopted, will allow SDG&E to continue to invest in its system during the TY 2024 GRC cycle while also providing SDG&E with a fair opportunity to earn its authorized rate of return.

A Two-part Post-Test Year Mechanism Was Approved for Southern California Edison Company's 2025 Test Year General Rate Case

16. D.25-09-030 was issued September 23, 2025 in Southern California Edison Company's ("SCE") TY 2025 GRC (hereinafter referred to as the "SCE 2025 GRC Decision").

17. The SCE 2025 GRC Decision authorized a two-part post-test year mechanism that separately escalates O&M and capital.

18. In the SCE 2025 GRC Decision, post-test year capital revenue requirement was calculated based on test year capital additions with zero escalation.

19. Table 4 below shows what the post-test year revenue requirements would be for SDG&E calculated under a two-part post-test year mechanism, using the methodology authorized in SCE's 2025 GRC Decision. The results in Table 4 include the O&M component of the mechanism and the budget-based capital exception for Covered Conductor and Strategic Undergrounding, consistent with the 2024 GRC Decision.

Table 4. SDG&E Revenue Requirement Using SCE's Two-Part Methodology

$ in millions	2024	2025	2026	2027
TY Capital Additions 2024	$2,699	$2,922	$3,129	$3,324

20. The 2024 GRC Decision authorized a post-test year revenue requirement for 2025-2027. Table 5 below provides the incremental revenue requirement when applying SCE's 2025 GRC Decision (test year capital additions with zero escalation) to SDG&E.

Table 5. SDG&E Incremental Revenue Requirement Using SCE Attrition Methodology

$ in millions	2024	2025	2026	2027
Authorized				
Total Revenue Requirement	$2,699	$2,846	$2,965	$3,086
Increase (a)	$0	$147	$119	$121
Test-Year Capital Additions (2024)				
Total Revenue Requirement	$2,699	$2,922	$3,129	$3,324
Increase (b)		$224	$206	$195
Incremental Increase from Authorized (b)-(a)[10]	$0	$77 2.8%	$87 2.9%	$74 2.1%

21. Using the methodology approved for SCE, the incremental revenue requirement for SDG&E, if granted, is $77 million for 2025, $87 million for 2026, and $74 million for 2027.

The Commission Should Grant a Seven-Year Average of Capital Additions as the Capital Component of a Two-Part Attrition Mechanism

22. The Commission should grant a modification of the post-test year mechanism from the adopted one-part mechanism to a two-part mechanism. To calculate the capital component, the Commission should use the seven-year average of capital additions methodology based on 2018-2021 recorded information and 2022-2024 forecasts authorized in the 2024 GRC Decision.

23. Using this seven-year average methodology is reasonable for the same reasons the Commission found reasonable in the 2019 GRC Decision:

> We find that using a seven-year average using recorded and forecasted capital additions for 2013 to 2019 more reasonably reflects both historical adjustments as well as current and forward-looking additions in light of the evolving changes brought about by the utilities' focus on increasing investment in utility safety and reliability and investments aimed at mitigating safety risk and providing clean and reliable energy.
>
> While we agree with Applicants' forward-looking focus and increased programs on improving safety, risk mitigation, grid modernization, and support of California's clean energy and environmental initiatives, it is not certain at this point in time at what level these activities will continue to increase and whether or

[10] Represents the differential between the year-over-year increases.

> not and at what point additional spending efficiently matches the amount of risk reduction and increased safety. Thus, we find that it is also important to incorporate historical adjustments. A seven-year average provides a more effective normalization of capital additions.[11]

24. Additionally, comparing the resulting revenue requirement increases in Table 3 and Table 5 demonstrates that the seven-year average is the most modest option discussed herein.

25. Table 6 below provides the results of SDG&E proposed seven-year average methodology in this Petition broken down by gas and electric revenue requirements.

Table 6. Electric & Gas Revenue Requirement Using Seven-Year Average of Capital Additions

$ in millions	2024	2025	2026	2027
Revenue Requirement Total	$2,699	$2,901	$3,107	$3,308
Electric Revenue Requirement	$2,193	$2,338	$2,513	$2,685
Gas Revenue Requirement	$506	$563	$594	$623

Revenue Requirement is Needed to Support Wildfire Mitigation Work Required by the Office of Energy Infrastructure Safety

26. The Declaration of Jonanthan Woldemariam describes SDG&E's Petition to Amend various wildfire mitigation programs filed with the Office of Energy Infrastructure Safety ("Energy Safety"). Energy Safety denied SDG&E's request to adjust the targets for four wildfire mitigation capital programs. Accordingly, Mr. Woldemariam forecasts the incremental capital expenditures beyond the authorization in the 2024 GRC Decision to complete the work required by Energy Safety.

27. Based on Mr. Woldemariam's capital expenditures forecasts, I modeled and calculated the incremental revenue requirement for each WMP capital program for which the Petition to Amend was denied. Overhead rates and escalation were applied consistently with the 2024 GRC Decision. To perform these revenue requirement calculations, I utilized the same

[11] D.19-09-051 at 708-709 (internal footnotes omitted).

model that the Commission used to calculate the budget-based capital exception for Covered Conductor and Strategic Undergrounding in the 2024 GRC Decision. The assumptions, such as tax and working cash, are consistent with the model adopted by the Commission in the 2024 GRC Decision.

28. The revenue requirements for the four capital programs, modeled as a budget-based capital exception, are provided in Table 7 below.

Table 7. Revenue Requirement for Capital WMP Programs Denied in Petition to Amend

WMP Program ***($ in Thousands)***	**2025**	**2026**	**2027**
Drone Assessments	$493	$3,751	$6,826
Hotline Clamps	$14	$95	$104
Expulsion Fuse Replacements	$29	$198	$221
Avian Protection	$42	$294	$324
Total[12]	$577	$4,338	$7,475

29. Although the revenue requirement needed to perform the underfunded wildfire mitigation work Energy Safety mandated is approximately $12.4 million for 2025-2027, SDG&E requests in this Petition that the Commission authorize an adjustment to the capital component of the PTY mechanism to incorporate the seven-year average of capital additions. If the Commission grants the requested relief in this Petition, SDG&E will use the revised PTY mechanism's funding to cover the costs associated with these four wildfire mitigation programs.

30. SDG&E requests that the Commission adopt a two-part PTY mechanism with the capital component calculated using the seven-year average of capital additions.

[12] Totals may include rounding differences.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 17th day of December 2025, at San Diego, California.

/s/ Melanie E. Hancock
Melanie E. Hancock

ATTACHMENT C.1

SDG&E WORKPAPERS TO DECLARATION OF MELANIE E. HANCOCK ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

Revenue Requirement:

SDG&E PTY		7-Year Avg Capital Additions				FD				FD less 7-Year Avg Scenario			
Line No.	Description ($ in millions)	TY - 2024	PTY – 2025	PTY – 2026	PTY – 2027	TY - 2024	PTY – 2025	PTY – 2026	PTY – 2027	TY - 2024	PTY – 2025	PTY – 2026	PTY – 2027
1	O&M Related Costs	958.9	987.6	1,017.3	1,047.8	958.9	987.6	1,017.3	1,047.8	-	-	-	-
2	Capital Related Costs (Depreciation, Taxes, Return)	1,644.1	1,777.7	1,910.8	2,045.4	1,644.1	1,693.4	1,744.2	1,796.5	-	84.3	166.5	248.9
3	PTY Capital Exceptions Related Cost	-	32.5	66.6	101.2	-	32.5	66.6	101.2	-	-	-	-
4	Base Margin excluding FF&U (L1 + L2 + L3)	2,603.0	2,797.9	2,994.6	3,194.4	2,603.0	2,713.6	2,828.1	2,945.6	-	84.3	166.5	248.9
5	FF&U	91.5	93.7	96.0	98.4	91.5	95.2	99.3	103.5	-	(1.6)	(3.3)	(5.2)
6	Total Base Margin (L4 + L5)	2,694.4	2,891.6	3,090.6	3,292.8	2,694.4	2,808.8	2,927.4	3,049.1	-	82.8	163.2	243.7
7	Miscellaneous Revenues	37.1	37.1	37.1	37.1	37.1	37.1	37.1	37.1	-	-	-	-
8	**Total Revenue Requirement (L6 + L7)**	**2,731.5**	**2,928.6**	**3,127.7**	**3,329.9**	**2,731.5**	**2,845.9**	**2,964.5**	**3,086.2**	**-**	**82.8**	**163.2**	**243.7**
9	2023 Tax Benefit including FF&U	(32.7)	-	-	-	(32.7)	-	-	-	-	-	-	-
10	COC Adjustment (incl FF&U)	-	(28.4)	(31.0)	(33.6)	-	-	-	-	-	(28.4)	(31.0)	(33.6)
11	FF&U Adjustment	-	1.0	10.6	11.7	-	-	-	-	-	1.0	10.6	11.7
12	**Adjusted Total Revenue Requirement (L8 + L9 + L10 + L11)**	**2,698.9**	**2,901.3**	**3,107.3**	**3,308.0**	**2,698.9**	**2,845.9**	**2,964.5**	**3,086.2**	**-**	**55.4**	**142.8**	**221.8**
13	Revenue Requirement Increase $		202.4	206.0	200.7		147.0	118.6	121.7		55.4	87.4	79.0
14	Revenue Requirement Increase %		*7.50%*	*7.10%*	*6.46%*		*5.45%*	*4.17%*	*4.11%*		*2.05%*	*2.93%*	*2.35%*

Wildfire Mitigation Capital Programs:

($ in dollars)

Expulsion Fuse Replacements	Total	2025	2026	2027
Revenue Requirement				
FF&U	**$ 16,190**	$ 1,039	$ 7,163	$ 7,988
O&M	**0**	0	0	0
Working Capital	**0**	0	0	0
Depreciation	**162,924**	11,442	71,457	80,025
Return on Common	**141,051**	10,511	63,667	66,873
Return on Preferred	**4,535**	338	2,047	2,150
Return on Debt	**52,072**	3,880	23,504	24,688
Federal Taxes	**41,026**	2,635	19,640	18,751
State Taxes	**8,788**	(1,108)	5,270	4,625
Property Taxes	**21,293**	0	5,402	15,891
Total Rev Req	**$ 447,880**	**$ 28,738**	**$ 198,150**	**$ 220,992**

($ in dollars)

Drone Assessments	Total	2025	2026	2027
Revenue Requirement				
FF&U	**$ 400,145**	$ 17,815	$ 135,590	$ 246,740
O&M	**0**	0	0	0
Working Capital	**0**	0	0	0
Depreciation	**4,061,511**	162,249	1,241,453	2,657,808
Return on Common	**3,490,798**	191,333	1,286,106	2,013,359
Return on Preferred	**112,245**	6,152	41,354	64,739
Return on Debt	**1,288,706**	70,635	474,795	743,277
Federal Taxes	**1,024,084**	51,363	384,818	587,904
State Taxes	**238,522**	(6,717)	88,209	157,029
Property Taxes	**453,609**	0	98,636	354,973
Total Rev Req	**$ 11,069,621**	**$ 492,829**	**$ 3,750,962**	**$ 6,825,829**

($ in dollars)

Avian Protection	Total	2025	2026	2027
Revenue Requirement				
FF&U	**$ 23,841**	$ 1,524	$ 10,608	$ 11,709
O&M	**0**	0	0	0
Working Capital	**0**	0	0	0
Depreciation	**292,569**	20,547	128,317	143,704
Return on Common	**180,503**	13,742	82,333	84,429
Return on Preferred	**5,804**	442	2,647	2,715
Return on Debt	**66,637**	5,073	30,395	31,169
Federal Taxes	**53,013**	3,216	25,770	24,027
State Taxes	**9,674**	(2,397)	6,353	5,717
Property Taxes	**27,488**	0	7,034	20,454
Total Rev Req	**$ 659,528**	**$ 42,147**	**$ 293,457**	**$ 323,924**

($ in dollars)

Hotline Clamps	Total	2025	2026	2027
Revenue Requirement				
FF&U	**$ 7,705**	$ 494	$ 3,432	$ 3,779
O&M	**0**	0	0	0
Working Capital	**0**	0	0	0
Depreciation	**98,280**	6,902	43,104	48,273
Return on Common	**56,203**	4,301	25,702	26,200
Return on Preferred	**1,807**	138	826	842
Return on Debt	**20,749**	1,588	9,488	9,672
Federal Taxes	**16,590**	1,003	8,101	7,486
State Taxes	**3,236**	(772)	2,096	1,911
Property Taxes	**8,578**	0	2,199	6,378
Total Rev Req	**$ 213,146**	**$ 13,654**	**$ 94,949**	**$ 104,543**

ATTACHMENT D

RYAN HOM DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	A.22-05-015 (Filed May 16, 2022)
And Related Matter.	A.22-05-016 (Filed May 16, 2022)

DECLARATION OF RYAN HOM ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.24-12-074

I, Ryan Hom, declare that:

1. I am currently employed by Southern California Gas Company ("SoCalGas") as the General Rate Case Financial Analysis Manager. My organization is responsible for developing the revenue requirement forecasts for both SoCalGas and San Diego Gas & Electric Company ("SDG&E") (collectively, the "Companies"). I sponsored testimony on behalf of SoCalGas and SDG&E in Track 1 of the above-captioned Test Year ("TY") 2024 General Rate Case ("GRC") proceeding, supporting Summary of Earnings.[1]

2. The purpose of my declaration is to provide factual support for the Companies' Petition for Modification ("Petition" or "PFM") of Decision ("D.") 24-12-074, issued on December 23, 2024 (hereinafter referred to as the "2024 GRC Decision") based on data from the Results of Operations ("RO") model.

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[1] Exhibits ("Ex.") SDG&E-44-R, SDG&E-52, SCG-39-2R, SCG-44, SCG-401/SDG&E-401.

3. The RO model is the model used both for the Companies to calculate their respective test year revenue requirement request and for the Commission to calculate the authorized test year revenue requirements.

4. In addition to calculating revenue requirements, the RO model houses many data inputs that feed into the revenue requirement calculations. These data inputs include program and project information, such as authorized forecasts and in-service dates. Other data inputs include depreciation parameters, rate base, tax, and others.

5. For this Petition, the Companies leveraged data from the RO model that supports the revenue requirement calculations authorized in the Commission's TY 2024 GRC Decision.

The Companies Have a Significant Amount of Routine Capital Costs with In-Service Dates in 2024

6. Using the data in the RO model, I reviewed the capital projects and programs authorized by the Commission in the 2024 GRC Decision. The Companies have two types of capital costs. The first type of capital costs are projects with a specific in-service date. An example may include a discrete capital project that the utility implements on a specific date all at once. The second type of capital costs are routine, sometimes referred to as blankets. Routine capital work has periodic in-service dates for which the programs close to plant on a frequent basis, such as monthly or quarterly. An example of routine programs are proactive replacement programs, such as valves or switches.

7. The majority of SoCalGas's and SDG&E's capital costs support routine work. This type of routine work is addressed in the majority of operational witness areas in the 2024 GRC, such as operational area Electric Distribution, Gas Distribution, Gas Transmission, and Gas Storage. Over the 2022-2024 test-year period, approximately 74% of SoCalGas's authorized capital expenditures and 71% of SDG&E's are recurring in nature. Because the

Companies are completing most of their capital work routinely and programmatically, funding is necessary in the post-test years to continue such programs at a level commensurate with the test year forecast. The 2024 GRC Decision's one-part post-test year mechanism does not provide adequate funding to continue to invest in routine capital work. For both Companies, there is approximately $5 billion of inadequately funded recurring capital projects over the 2025-2027 post-test year period in total.

8. Estimated in-service dates factor into the RO model's revenue requirement calculation. Specifically, in-service dates impact the timing of plant additions and the weighted average rate base calculation. Therefore, the revenue requirement of a given project or program will differ depending on the in-service date.

9. Based on the in-service date, the revenue requirement is pro-rated for the first year. This means that a capital project that has an in-service date after January 1 of the test year will not receive the total necessary revenue requirement in the test year and a post-test year ("PTY") mechanism based on test year revenue requirement that uses a flat percentage increase will not make the Companies whole in the post-test years.

10. When looking at in-service dates, approximately 20% of SoCalGas and SDG&E's approved capital expenditures had estimated in-service dates between January 31 through December 31 in 2024. For these authorized capital expenditures, the total is over $1 billion. Moreover, in December 2024 alone, SoCalGas and SDG&E forecasted approximately $223 million and $327 million in capital expenditures respectively, to go into service. For December 2024 in-service dates, the authorized post-test year mechanism only provides a small fraction of the necessary funding in the post-test years for these approved programs.

A Substantial Decrease in Capital Expenditures Would be Necessary to Operate Within the Authorized Post-Test Year Revenue Requirement

11. In the TY 2024 GRC Decision, the Commission authorized a TY revenue requirement of $3.8 billion for SoCalGas and $2.7 billion for SDG&E, or $6.5 billion total for both Companies. Of this total test year revenue requirement, the authorized capital-related revenue requirement is $2.1 billion for SoCalGas and $1.6 billion for SDG&E, or $3.7 billion for the Companies. The authorized capital-related revenue requirement for 2025, 2026, and 2027 are $3.9 billion, $3.9 billion, and $4.1 billion, respectively.[2] Table 1 below summarizes the authorized total and capital-related revenue requirements for 2024-2027 and shows that the capital-related revenue requirement is over half of the Companies' revenue requirements.

Table 1. Companies' Authorized Revenue Requirements

$ in millions	**2024**	**2025**	**2026**	**2027**
Total Authorized Revenue Requirement	$6,505	$6,842	$7,077	$7,318
Capital Related Revenue Requirement[3]	$3,762	$3,875	$3,991	$4,111
Capital Related Revenue Requirement Percentage		57%	56%	56%

12. The basis for the authorized capital-related revenue requirement is the ongoing recovery of recorded assets authorized in previous GRCs and new capital additions associated with the direct capital expenditures adopted in the 2024 GRC. The 2024 GRC Decision authorized direct capital expenditures for the Companies of $2.4 billion, $2.4 billion, $2.5 billion for years 2022, 2023, and 2024, respectively.[4] These capital expenditures are inputs into the 2024 authorized revenue requirement.

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[2] Excludes the capital-related revenue requirement costs for the Wildfire Mitigation programs of Covered Conductor and Strategic Undergrounding that were separately authorized as a PTY Capital Exception in D.24-12-074.

[3] See *supra* at footnote 2.

[4] Does not include loaders or overheads. Amounts in constant 2021 dollars.

13. In the 2024 GRC Decision, the Commission authorized revenue requirements for 2025-2027, but did not authorize specific capital expenditures. Therefore, the Companies started with the authorized capital-related revenue requirements for 2025, 2026, and 2027 of $3.9 billion, $3.9 billion, and $4.1 billion, respectively, and calculated an estimated level of capital expenditures that are supported by the authorized PTY revenue requirements.[5] Table 2 below summarizes the authorized and estimated capital expenditures for 2024-2027.

Table 2. Companies' Capital Expenditures that Support the Authorized Capital-Related Revenue Requirement

Nominal $ in millions	2024 Authorized	2025 Estimated	2026 Estimated	2027 Estimated
SoCalGas	$1,350	$591	$609	$627
SDG&E	$1,443	$899	$926	$953
Total	$2,793	$1,490	$1,535	$1,580

14. In the adopted post-test year mechanism, the authorized revenue requirement increases by about 3% annually. While the revenue requirement grows by about 3% in each post-test year, the capital expenditures that are supported by the revenue requirement do not follow the same pattern of approximately 3% escalation.

15. To remain within the authorized revenue requirements for 2025-2027, the capital expenditures for SoCalGas and SDG&E for 2025-2027 will decline as shown in Table 3 below.

Table 3. Estimated Capital Expenditures that Support Post-Test Year Revenue Requirements Approved in D.24-12-074
(Direct nominal, $ in millions)

Capital Expenditures	TY 2024	2025	2026	2027
SoCalGas	$1,350	$591	$609	$627
SDG&E	$1,443	$899	$926	$953
Total	$2,793	$1,490	$1,535	$1,580
$ Change compared to TY		(-$1,303)	(-$1,258)	(-$1,213)
% Change compared to TY		(-47%)	(-45%)	(-43%)

[5] *See supra* at footnote 2.

16. Accordingly, to manage within the authorized revenue requirement, the Companies would be required to decrease combined capital expenditures from nearly $2.8 billion authorized in TY 2024 to about $1.5 billion per year on average during the post-test years. That equates to an average annual capital expenditure decrease of 46%, or over $1.3 billion per post-test year, and a total decrease of over $3.9 billion in capital expenditures over the TY 2024 GRC cycle.

Attachment I of the Petition is a True and Correct Copy

17. Attachment I of the Petition is a whitepaper titled, *Post Test Year Ratemaking: Timing, Attrition, and the Balancing of Interests.*

18. This whitepaper was received from Karl A. McDermott Ph. D. and Professor Carl R. Peterson Ph.D., Professors of the University of Illinois, Springfield.

19. I confirm that the version of the whitepaper attached to the Petition is a true and correct copy of *Post Test Year Ratemaking: Timing, Attrition, and the Balancing of Interests*, by Drs. McDermott and Peterson.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 17th day of December 2025, at Los Angeles, California.

/s/ Ryan Hom
Ryan Hom

ATTACHMENT E

BILL G. KOSTELNIK DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	A.22-05-015 (Filed May 16, 2022)
And Related Matter.	A.22-05-016 (Filed May 16, 2022)

DECLARATION OF BILL G. KOSTELNIK ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.24-12-074

I, Bill G. Kostelnik, declare that:

1. I am currently employed by Southern California Gas Company ("SoCalGas") as the Project Management Office Performance & Strategy Manager. My current responsibilities include planning, development, and implementation of regulatory proceedings within the Infrastructure Project Delivery organization. I sponsored testimony on behalf of SoCalGas in Track 1 of the above-captioned Test Year ("TY") 2024 General Rate Case ("GRC") proceeding, supporting the Pipeline Safety Enhancement Plan ("PSEP") requests. I am familiar with and involved with PSEP for both SoCalGas and San Diego Gas & Electric Company ("SDG&E") (collectively, "the Companies")

2. The purpose of my declaration is to provide factual support for SoCalGas's assertions related to PSEP in the Petition for Modification ("Petition") of Decision ("D.") 24-12-074, issued on December 23, 2024 (hereinafter referred to as the "2024 GRC Decision").

Background

3. The Companies' PSEP program is mandated by the Commission in D.11-06-017 (later codified in California Public Utilities Code ("Pub. Util. Code") Sections 957 and 958) and D.14-06-007. The program was initiated after a 30-inch diameter natural gas transmission pipeline ruptured and caught fire in the city of San Bruno, California, and the Commission and legislature determined that "natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety," and that there must be traceable, verifiable records of such compliance.[1]

4. PSEP is a safety-related program that was included in SoCalGas's 2021 RAMP filing and remains an important control/mitigation of the risk entitled *Incident Related to the High Pressure System (Excluding Dig-in)*.

2024 GRC

5. As I explained in my Track 1 direct testimony, the four objectives of PSEP are: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments.[2]

6. For SoCalGas, given the size, scope, and complexity of PSEP projects, a project-specific cost estimate was developed for each pipeline project using a zero-based approach.

7. Rather than presenting a forecast that relies on the execution of specific projects in specific years, SoCalGas instead requested Commission authorization for PSEP projects "based on an anticipated level of executable spending from a portfolio of 33 Phase 1B and 2A pipeline projects" over the GRC cycle.[3]

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[1] D.11-06-017 at 18.
[2] Exhibit ("Ex.") SCG-08 at BGK-8.
[3] *Id.,* at 19 (citation omitted).

8. The 2024 GRC Decision authorized a capital expenditure forecast for SoCalGas of $108.969 million, $91.613 million, and $64.716 million for 2022, 2023, and 2024, respectively,[4] and also determined the reasonableness of the PSEP projects SoCalGas put forth.

9. Specifically, the 2024 GRC Decision found: "The 2022-2024 Pipeline Safety Enhancement Plan capital cost forecasts are reasonable based on Southern California Gas Company's 2022 recorded costs and the removal of project contingencies."[5]

Petition

10. One of the PSEP capital projects included in SoCalGas's 2024 GRC forecast that was authorized in Track 1 was Supply Line 38-539 Phase 2A Replacement Project.[6]

11. Although the project is a Phase 2A project because it is located in a lower population area, and therefore a lower priority project than those in Phase 1A and 1B, like all PSEP projects Supply Line 38-539 is required to be tested or replaced "as soon as practicable."[7] This project "will replace approximately 12.57 miles of pipeline"[8] that does not have sufficient documentation of a pressure test to at least 1.25 Maximum Allowable Operating Pressure ("MAOP").

12. Because of the post-test year mechanism authorized in the 2024 GRC Decision, and SoCalGas's authorization to perform work at an executable level of spending, SoCalGas does not have adequate funds to complete this PSEP replacement project at this time. Without the relief requested herein, SoCalGas will continue to defer this project until it has sufficient funding to complete it.[9]

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[4] *See* D.24-12-074, Table 12.10 at 228.
[5] *Id.,* Findings of Fact ("FOF") 64.
[6] *See id.* at 224-226 (removing contingency forecasts only).
[7] Public Utilities Code Section 958; D.11-06-017 at 18-19..
[8] Ex. SCG-08 at 27. *See also* Ex. SCG-08-WP-S, Volume 1-8 at 36-46.
[9] D.11-06-017 at 18-19.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 17th day of December 2025, at Los Angeles, California.

/s/ Bill G. Kostelnik
Bill G. Kostelnik

ATTACHMENT F

JONATHAN T. WOLDEMARIAM DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	A.22-05-015 (Filed May 16, 2022)
And Related Matter.	A.22-05-016 (Filed May 16, 2022)

DECLARATION OF JONATHAN T. WOLDEMARIAM ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.24-12-074

I, Jonathan T. Woldemariam, declare that:

1. I am currently employed by San Diego Gas & Electric Company ("SDG&E") as the Director of Wildfire Mitigation. My current responsibilities include developing and overseeing the execution of SDG&E's Wildfire Mitigation Plan ("WMP"), which includes the vegetation management program. I work to optimize a portfolio of initiatives to help decrease wildfire risk. I sponsored testimony on behalf of SDG&E in Track 1 of the above-captioned Test Year ("TY") 2024 General Rate Case ("GRC") proceeding, supporting Wildfire Mitigation and Vegetation Management.

2. My declaration supports the Petition for Modification ("Petition" or "PFM") of Decision ("D.") 24-12-074, issued on December 23, 2024 (hereinafter referred to as the "2024 GRC Decision"), by explaining why the currently authorized post-test year mechanism fails to support most of SDG&E's wildfire mitigation programs, leaving it with insufficient funding to complete capital-related WMP initiatives that require ongoing capital additions.

3. In the 2024 GRC Decision, the Commission authorized a budget-based capital exception for the two wildfire mitigation programs of covered conductor and strategic

undergrounding. All other wildfire mitigation programs, besides covered conductor and strategic undergrounding, are subject to the 2024 GRC Decision's authorized post-test year mechanism of 3% escalation of the test year revenue requirement.

SDG&E's Petition to Amend the 2023-2025 Wildfire Mitigation Plan

4. On March 27, 2023, SDG&E submitted for approval a three-year WMP to the Office of Energy Infrastructure Safety ("Energy Safety") to address 2023-2025 wildfire mitigation initiatives. SDG&E also provided an annual update for 2025. The WMP process results in obligations and targets for which SDG&E must comply. Funding for the WMP initiatives approved by Energy Safety, however, is determined by the Commission. For this WMP cycle of 2023-2025, funding for 2024 and 2025 was determined in the 2024 GRC proceeding.

5. Energy Safety allows electrical corporations to amend previously approved WMP initiative targets under a very limited set of circumstances. These limited circumstances can include changes to funding due to a GRC decision.

6. By the time the Commission authorized the 2024 GRC Decision, Energy Safety had already approved SDG&E's 2025 WMP update, including the associated initiative targets, which form the basis for Energy Safety's review of WMP compliance. Thus, while the initiative targets had been approved by Energy Safety, funding to implement those targets had not been approved by the CPUC.

7. When the 2024 GRC Decision was issued, SDG&E analyzed the newly authorized GRC funding and determined that it was insufficient to complete the already committed to wildfire mitigation work.

8. To address this disconnect between required activity and available funding, on April 10, 2025, SDG&E submitted a Petition to Amend its 2023–2025 Wildfire Mitigation Plan

to Energy Safety ("Petition to Amend"), requesting adjustments for 2024 and 2025 to better align program scopes and budgets with the 2024 GRC Decision and operational realities. Specifically, the Petition to Amend sought approval to revise seventeen WMP initiatives and associated targets to reflect updated cost forecasts.

9. SDG&E explained in its Petition to Amend the revenue shortfall associated with the capital costs authorized in the 2024 GRC Decision and why these changes were needed:

> SDG&E calculated the revenue requirement for its wildfire mitigation program based upon its final GRC Decision. The revenue requirement includes (1) the revenue requirements for covered conductor and strategic undergrounding for each year of the GRC cycle, as explicitly authorized by the CPUC, and (2) the approximate 3 percent for all other wildfire mitigation programs. The table below provides the approved capital expenditures, the calculated authorized revenue requirement, the resulting revenue requirement shortfall, and the associated reduction in capital required to stay within the revenue requirement authorized for the overall wildfire mitigation program.[1]

2024 GRC | WMP (direct $, in millions)	2024	2025	2026	2027	Total
Authorized Capital Expenditures (Capex)	$396	$417	$425	$432	$1,670
Authorized Revenue Requirement	$16	$48	$82	$116	$262
Revenue Requirement necessary to complete Authorized Capex	$16	$64	$131	$199	$410
Revenue Requirement Shortfall	**-**	**($16)**	**($49)**	**($83)**	**($148)**
Reduction to Authorized Capex to align with Authorized Revenue Requirement	-	($199)	($184)	($201)	($584)
Adjusted Capex Target	**$396**	**$218**	**$241**	**$231**	**$1,086**
Actual/Forecasted Capex	**$474**	**$277**	**$153**	**$141**	**$1,045**

10. SDG&E further explained that to "stay within the authorized revenue requirement and because SDG&E exceeded its capital expenditures in 2024, it is necessary to reduce SDG&E's wildfire mitigation spending for 2025, 2026, and 2027."[2]

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[1] SDG&E 2025 Petition to Amend (April 10, 2025) ("Petition to Amend") at 5, *available at*: https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58234&shareable=true.
[2] *Id.* at 5.

11. The changes to SDG&E's covered conductor and strategic undergrounding programs requested in the Petition to Amend were rooted in the Commission's approval of specific mileages for both hardening mitigations over the GRC cycle. Because the ongoing capital requirements for these two programs are funded through a budget-based capital exception, the 2024 GRC Decision provides continued capital additions to meet annualized targets through the GRC cycle.

12. All the remaining programs for which SDG&E requested an adjustment in the Petition to Amend are subject to the authorized post-test year mechanism of escalating test year revenue requirement by 3%.[3] Yet, as with strategic undergrounding and covered conductor, the other wildfire mitigation programs require ongoing capital additions to make necessary repairs and reduce wildfire risk. This is because SDG&E is regularly and proactively replacing assets, when necessary, thus requiring ongoing capital funding to continue these programs.

13. The authorized one-part post-test year mechanism fails to authorize sufficient funds to allow for these ongoing capital additions in the post-test years. All capital wildfire mitigation programs, other than covered conductor and strategic underground mitigations—including those critical to ignition prevention and system reliability—lack specific post-test year cost recognition. The Decision's escalation-based approach fails to capture cost increases associated with supply chain disruptions, field labor rates, and expanded program requirements under California's wildfire safety framework. The Petition to Amend requested reductions to the scope of these programs and explained that these adjustments were necessary to align program budgets with actual cost drivers and to ensure continued progress toward wildfire risk reduction objectives.[4]

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[3] *Id.* at 4.
[4] *See generally, id.*

14. On July 11, 2025, Energy Safety denied SDG&E's Petition to Amend with respect to four capital-related programs, namely Drone Assessments, Hotline Clamps, Avian Protection and Expulsion Fuse Replacements.[5] Table 1 summarizes SDG&E's requested amendments to targets and Energy Safety's decision on the specific requests.

Table 1. Summary of Petition to Amend Outcome

WMP Initiative	Unit	Original Target	Requested Target	Decision
Strategic Undergrounding (WMP.473)	miles	125	28	Approved
Covered Conductor (WMP.455)	miles	40	50	Approved
Strategic Pole Replacement Program (WMP.1189)	Poles	291	200	Approved
Transmission OH Hardening (WMP.543)	Miles	4.64	2	Approved
Distribution Communications Reliability Improvements (WMP.549)	base stations	42	5	Approved
Drone Assessments (WMP.552)	inspections	13,500	6,500	Denied
Lightning Arrester Removal/Replacement (WMP.550)	lightning arresters	1,848	90	Approved
Connectors, including hotline clamps (WMP.464)	hotline clamps	950	100	Denied
Avian Protection (WMP.972)	poles	200	95	Denied
Expulsion Fuse Replacement (WMP.459)	fuses	700	80	Denied
Detailed Vegetation Inspections (WMP.494)	inspections	485,400	255,000	Denied
Pole Clearing (WMP.512)	poles	33,010	22,000	Denied

15. In partially denying the Petition to Amend, Energy Safety required SDG&E to submit a revised WMP reflecting only the approved amended targets and associated cost forecasts.

[5] The programs of detailed vegetation inspections and pole clearing are comprised entirely of O&M expenses. As such, SDG&E does not address these programs in this Petition.

SDG&E's PTY Revenue Requirement is Inadequate to Fund WMP Implementation and Meet Regulatory Compliance Requirements

16. SDG&E is statutorily obligated to comply with and implement its approved WMP. Public Utilities Code Section 8389 requires electrical corporations to demonstrate ongoing implementation of its approved WMP through quarterly and annual reporting to Energy Safety and the Commission to receive a safety certificate. Public Utilities Code Section 8386.3, recently amended by Senate Bill ("SB") 254, also requires electrical corporations to annually report on implementation of WMP targets to Energy Safety, and establishes that utilities who fail to implement WMP targets are subject to fines and penalties.

17. While SDG&E maintains a memorandum account to capture incremental costs necessary to implement WMP programs, the uncertainty and delayed recovery associated with growing memorandum account balances creates negative impacts for customers as well as SDG&E.

18. SDG&E analyzed the costs associated with performing the work for each of the WMP capital programs that were denied in the Petition to Amend. SDG&E estimates that the targets denied in the Petition to Amend will require additional capital expenditures of $26.8 million in 2025, $14.4 million in 2026, and $4.1 million in 2027, as shown in Table 2 below.

Table 2. Additional Direct Costs of Unfunded Capital Programs Required by the WMP

WMP Program *($ in Thousands)*	Unit	Target	2025	2026	2027
Drone Assessments	Inspections	13,500	$22,001	$14,447	$4,130
Hotline Clamps	Clamps	950	$1,702		
Expulsion Fuse Replacements	Fuses	700	$1,550		
Avian Protection	Poles	200	$1,512		
Total			$26,765	$14,447	$4,130

19. The additional capital costs shown in Table 2 demonstrate that current authorized funding levels in the 2024 GRC Decision are below what is required to sustain each program's planned scope and performance targets and should be corrected. The amounts shown in the above table for 2025 reflect incremental costs required to align with those presented in the 2025 WMP Update. The amounts shown above for 2026 and 2027 reflect incremental costs required to align with those presented in the 2026-2028 WMP.[6]

20. The Hotline Clamps, Expulsion Fuse Replacements, and Avian Protection programs are all expected to come to an end at the end of 2025. SDG&E stated in its 2025 Petition to Amend that it plans to deploy these assets as part of Covered Conductor and Strategic Undergrounding, and "continue to replace them as needed as part of its Corrective Maintenance Program (CMP)."[7]

21. The drone program continues through the post-test years, changing annually based on the number of inspections estimated to be performed and the resulting repair needs. Accordingly, SDG&E specifically forecasted the drone program capital needs for the 2024 GRC cycle.

22. Absent a change to the post-test year mechanism for the WMP capital programs identified herein, namely SDG&E's drone inspection programs, SDG&E cannot sustain critical initiatives necessary to continue ongoing wildfire risk reduction. These constraints limit SDG&E's ability to proactively identify equipment defects, reduce ignition probability, and enhance system resilience in Tier 2 and Tier 3 High Fire Threat Districts.

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[6] 2025 WMP Update is available here: https://www.sdge.com/2025-wildfire-mitigation-plan. 2026-2028 WMP is available here: https://www.sdge.com/2026-2028-wildfire-mitigation-plan.
[7] Petition to Amend at 9.

23. This is particularly the case with respect to SDG&E's drone inspection programs. SDG&E sought authorization to reduce the number of risk-based drone inspections of infrastructure from 13,000 to 6,500. Due to the denial of that request, SDG&E's drone program is underfunded by approximately $22.0 million for 2025, as shown in Table 2.

24. The Commission highlighted the value of SDG&E's drone inspection programs in SDG&E's TY 2024 GRC decision, describing drone inspections of electrical infrastructure to reduce risk as an "improvement."[8] The Commission's recognition of the value of these inspection programs further supports, at a minimum, an expansion of the post-test year exception to facilitate the ongoing work and repairs associated with these programs.

25. SDG&E calculated the revenue requirement for the capital costs in Table 2 above. As described in the declaration of Melanie Hancock, modeled as a budget-based capital exception, the revenue requirement is approximately $0.6 million for 2025, $4.3 million in 2026, and $7.5 million.

26. Because SDG&E must implement its approved WMP and initiative targets in order to receive a safety certificate, the Commission should grant additional capital funding for each of the WMP programs for which Energy Safety denied SDG&E's Petition to Amend—Drone Assessments, Hotline Clamps, Avian Protection and Expulsion Fuse Replacements.[9] The PFM's requested two-part post-test year mechanism using a seven-year average of capital additions would result in adequate funding to cover the unfunded wildfire mitigation programs required by the WMP, even after SDG&E's attempt to amend those requirements after the Decision failed to fund them.

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[8] D.24-12-074 at 6.

[9] The programs of detailed vegetation inspections and pole clearing are comprised entirely of O&M expenses and therefore are unapplicable to this PFM seeking funding for capital expenses.

27. For the reasons stated herein, the Commission should authorize additional wildfire mitigation funding for the unfunded capital programs required by the WMP.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 17th day of December 2025, at San Diego, California.

/s/ Jonathan T. Woldemariam

Jonathan T. Woldemariam

ATTACHMENT F.1

SAN DIEGO GAS & ELECTRIC 2025 PETITION TO AMMEND
SUBMITTED TO THE OFFICE OF ENERGY INFRASTRUCTURE SAFETY

APRIL 10, 2025

San Diego Gas & Electric 2025 Petition to Amend

April 10, 2025

Electronic Filing

OEIS Docket No. 2023-2025-WMPs

Table of Contents

I. Petition to Amend

a. Introduction and Background

The Office of Energy Infrastructure Safety's (OEIS or Energy Safety) 2026-2028 Wildfire Mitigation Plan (WMP) Guidelines allow a utility to submit a Petition to Amend to amend its approved WMP to align with a California Public Utilities Commission (CPUC) decision in a general rate case (GRC) proceeding.[1] Energy Safety has also approved change order requests during the 2023 to 2025 WMP cycle based on updated understanding of requirements and targets resulting from the electrical corporation's current ratesetting proceeding.[2]

Energy Safety issued a final decision approving San Diego Gas and Electric Company's (SDG&E) 2023-2025 Base WMP on October 13, 2023. [3] SDG&E submitted a change order request on November 1, 2023, requesting revisions to 2024 targets (2024 Change Order Request)[4] and submitted a revised change order request incorporating additional information requested by Energy Safety on December 19, 2023.[5] Many of the target revisions contained in SDG&E's change order request were rooted in program adjustments to reflect SDG&E's then-pending Test Year 2024 General Rate Case (GRC), including SDG&E's Settlement Agreement on Wildfire Issues with Cal Advocates, which provided agreed upon reductions to SDG&E's original GRC forecasts. However, at the time SDG&E filed its original request to change the identified 2024 initiative targets, the CPUC had not yet issued a decision on SDG&E's GRC, thus SDG&E did not know its authorized funding for 2024 to 2027.

On May 31, 2024, Energy Safety approved in part and rejected in part SDG&E's request to change its 2024 WMP targets.[6] Specifically, Energy Safety rejected eight change requests because the proposed changes did not reduce risk, as then required in the Change Order guidelines. On December 23, 2024, the CPUC issued a final decision in SDG&E's Test Year 2024 GRC, rejecting the proposed Settlement Agreement and adopting further overall reductions to SDG&E's funding for 2024 to 2027, particularly with respect to wildfire hardening initiatives.[7] Subsequently, SDG&E submitted a Change Order Request on January 27, 2025, requesting to revise targets for 2024 and targets and expenditures for 2025 in its 2023-2025 Base WMP to align with the GRC decision.[8] On February 24, 2025, Energy Safety rejected the Change Order and ordered SDG&E to submit a Petition to Amend in accordance with the 2026-2028 WMP Guidelines as adopted on February 21, 2025.[9]

Consistent with Energy Safety's 2026-2028 WMP Guidelines and past decisions addressing previous change order requests, SDG&E herein requests the below described revisions to its 2024 and 2025 WMP

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[1] *Office of Energy Infrastructure Safety Wildfire Mitigation Plan Guidelines (February 24, 2025).*
[2] *Energy Safety Decision on Pacific Gas and Electric Company's (PG&E) Change Order Request in relation to its 2023-2025 Base WMP (May 31, 2024) (2024 PG&E Change Order Decision), Table 1 at 3-10.*
Office of Energy Infrastructure Safety Decision on 2023-2025 Wildfire Mitigation Plan San Diego Gas & Electric Company (October 13, 2023).[4] *San Diego Gas & Electric 2023 Change Order Report (November 1, 2023).*
[4] *San Diego Gas & Electric 2023 Change Order Report (November 1, 2023).*
[5] *Energy Safety Decision on SDG&E 2023 Change Order Report (December 19, 2023).*
[6] *Decision on SDG&E's Change Order Request in relation to its 2023-2025 Base WMP (May 31, 2024).*
[7] *D.24-12-074.*
[8] *San Diego Gas & Electric 2025 Change Order Request (January 27, 2025.)*
[9] *Denial of Extension Request for 2025 Wildfire Mitigation Plan Update Change Order Request and the Change Order Request (February 24, 2025).*

initiative targets and 2025 initiative spend. Energy Safety should approve the requested revisions as they reflect alignment with SDG&E's GRC decision, as further addressed below.[10]

b. Summary

Funding determinations for the initiatives described in SDG&E's 2023-2025 Base WMP, specifically for 2024 and 2025, were addressed by the CPUC in SDG&E's Test Year 2024 GRC Application (A.) 22-05-016. On December 23, 2024, the CPUC issued Decision (D.) 24-12-074, the final decision in SDG&E's 2024 GRC (GRC Decision), setting SDG&E's revenue requirement for 2024 to 2027. The GRC Decision adopted several significant reductions to SDG&E's requested wildfire mitigation costs. Accordingly, revisions to WMP targets for 2024 and 2025 are necessary to align with the GRC Decision.

Because the GRC Decision was issued at the end of Test Year 2024, SDG&E had largely completed its WMP-related work in 2024 without funding guidance. As described above, without such guidance, SDG&E based its wildfire-mitigation spending for 2024 on the Settlement Agreement with Cal Advocates, which was ultimately rejected by the CPUC, who further reduced authorized funding. SDG&E's requested 2024 WMP changes are thus justified as necessary to align with the funding levels authorized in its GRC. Further, in an effort to perform wildfire safety work within its authorized revenue requirement, SDG&E must adjust 2025 targets in its 2023-2025 Base WMP to reflect the GRC Decision. For capital work specifically, SDG&E manages such work over a GRC cycle (i.e., 2024 to 2027). Because SDG&E exceeded its capital-related authorized revenue requirement in 2024, SDG&E proposes to decrease wildfire mitigation investment in 2025 to 2027.

The table below presents initiatives for which SDG&E is requesting a target change consistent with the GRC Decision. A discussion describing the rationale for each requested target change is provided in Sections II and III. See Attachment A for a complete listing of SDG&E's revised WMP portfolio including initiative targets and projected capital and O&M spend.

WMP Initiative	Unit	Original Target	Requested Target
2024 Requested Changes			
Distribution Communications Reliability Improvements (WMP.549)	base stations	60	5
Standby Power Program (WMP.468)	generators	300	58
Drone Assessments (WMP.552)	inspections	13,500	6,500
Distribution Infrared Inspections (WMP.481)	inspections	9,532	300
Fuels Management (WMP.497)	poles	500	150
2025 Requested Changes			
Strategic Undergrounding (WMP.473)	miles	125	28
Covered Conductor (WMP.455)	miles	40	50

[10] *Consistent with the Guidelines, SDG&E has attached to this Petition Attachment A, a Revised Initiative Targets and Projected Capital and O&M Expenditure Chart and Attachment B, redlines to the affected portions of the 2023-2025 Base WMP.*

WMP Initiative	Unit	Original Target	Requested Target
Strategic Pole Replacement Program (WMP.1189)	Poles	291	200
Transmission OH Hardening	Miles	4.64	2
Distribution Communications Reliability Improvements (WMP.549)	base stations	42	5
Drone Assessments (WMP.552)	inspections	13,500	6,500
Lightning Arrester Removal/Replacement (WMP.550)	lightning arresters	1,848	90
Connectors, including hotline clamps (WMP.464)	hotline clamps	950	100
Avian Protection (WMP.972)	poles	200	95
Expulsion Fuse Replacement (WMP.459)	fuses	700	80
Detailed Vegetation Inspections (WMP.494)	inspections	485,400	255,000
Pole Clearing (WMP.512)	poles	33,010	22,000

c. SDG&E's General Rate Case

In May 2022, SDG&E filed its Test Year 2024 GRC Application with the CPUC requesting, among other things, approval of wildfire mitigation cost forecasts for 2024 to 2027.[11] These GRC forecasts formed the basis for the development of SDG&E's original 2024 and 2025 WMP initiatives and targets.

In October 2023, SDG&E, Southern California Gas Company, and the California Public Advocates Office (Cal Advocates) filed a joint motion in the 2024 GRC proceeding requesting CPUC approval of a Settlement Agreement on various issues (Settlement Agreement), including SDG&E's wildfire mitigation costs.[12] The Settlement Agreement proposed agreed-upon reductions in both capital and O&M requested spend for various WMP initiatives in 2024 to 2027. To plan work for 2024 and reflect the anticipated reductions in capital and O&M consistent with the Settlement Agreement, SDG&E filed a Change Order Request seeking to revise its 2024 WMP targets. While SDG&E did not have a final decision in its GRC, this 2024 Change Order Request sought Energy Safety's approval to align 2024 WMP targets with the cost reductions outlined in the Settlement Agreement. While Energy Safety did not approve some of the requested changes, Energy Safety approved similar requests in light of a final decision in a General Rate Case.[13]

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[11] *Application of San Diego Gas & Electric Company (U 902 M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2024 (May 16, 2022)*

[12] *Joint Motion of Southern California Gas Company (U 904-G), San Diego Gas & Electric Company (U 902-M), and The Public Advocates Office for Adoption of Settlement Agreements Resolving Various Issues in the 2024 General Rate Case (October 24, 2025)*

[13] *See, 2024 PG&E Change Order Decision.*

In December 2024, the conclusion of the Test Year, the CPUC issued a final decision in SDG&E's rate case. The GRC Decision and the funding authorized was effective retroactively to January 1, 2024. Relevant to wildfire mitigation, the CPUC's GRC Decision:

- Denied the Settlement Agreement.
- Authorized O&M and capital expenditure forecasts for all wildfire mitigation initiatives for Test Year 2024.
- Adopted explicit capital expenditure forecasts and capital-related revenue requirements for covered conductor and strategic undergrounding for 2024, 2025, 2026, and 2027.
- With the exception of covered conductor and strategic undergrounding, authorized a total revenue requirement for SDG&E's operations, including wildfire, of about 3 percent for each post-test year (2025, 2026, and 2027).
- Continued SDG&E's Wildfire Mitigation Plan Memorandum Account (WMPMA).
- Converted the two-way Tree Trimming Balancing Account to a one-way Vegetation Management Balancing Account and authorized a memorandum account to record vegetation management costs exceeding authorized.
- While the CPUC authorized specific capital funding for 2025 to 2027 for covered conductor and strategic undergrounding, it did not authorize a similar wildfire-specific funding mechanism for all wildfire mitigation costs. Instead, all other wildfire mitigation programs are subject to the post-test year flat percentage of about 3 percent, consistent with all of SDG&E's revenues.

The adopted post-test year amounts are calculated beginning with the Test Year 2024 revenue requirement. It is then escalated each year by about 3 percent. Particularly relevant to ongoing capital costs, it is important to note that it is not the O&M and capital expenditures that are escalated by about 3 percent, it is the revenue requirement.

In utility ratemaking, the costs of capital assets are implemented in rates over the life of the asset. Electric equipment on average has long lives, meaning an asset is in-service for many decades. Because of this, an approximately equal proportion of the authorized capital cost is recovered each year for many years. For example, if a new capital asset is put in service in 2024, then SDG&E will collect that year's portion of the capital costs in rates. Assuming no other capital investment, in 2025, SDG&E will collect the next year's portion of the remaining capital costs for the asset plus about 3 percent. The 3 percent is not enough revenue to invest in new capital but rather allows SDG&E to continue to service the 2024 capital asset.

A flat post-test year percentage is designed for base utility capital investments, such as older capital assets with corresponding authorized revenues that are already in rates. As those assets are retired and replaced with new assets, the authorized revenue amount increases modestly (i.e., 3 percent) to cover the incremental cost of asset replacements and capital repairs. This sharply contrasts with the wildfire mitigation capital programs, which require ongoing incremental (i.e., new) capital investment and incremental revenue requirement. Accordingly, if SDG&E were to spend its authorized O&M and capital expenditures each year of the GRC cycle, SDG&E would exceed its authorized revenue requirement. This is because the capital funding necessary to perform the work is beyond the approximately 3 percent post-test year authorized percentage.

SDG&E calculated the revenue requirement for its wildfire mitigation program based upon its final GRC Decision. The revenue requirement includes (1) the revenue requirements for covered conductor and strategic undergrounding for each year of the GRC cycle, as explicitly authorized by the CPUC, and (2) the approximate 3 percent for all other wildfire mitigation programs. The table below provides the approved capital expenditures, the calculated authorized revenue requirement, the resulting revenue requirement shortfall, and the associated reduction in capital required to stay within the revenue requirement authorized for the overall wildfire mitigation program.

2024 GRC | WMP (direct $, in millions)	2024	2025	2026	2027	Total
Authorized Capital Expenditures (Capex)	$396	$417	$425	$432	$1,670
Authorized Revenue Requirement	$16	$48	$82	$116	$262
Revenue Requirement necessary to complete Authorized Capex	$16	$64	$131	$199	$410
Revenue Requirement Shortfall	**-**	**($16)**	**($49)**	**($83)**	**($148)**
Reduction to Authorized Capex to align with Authorized Revenue Requirement	-	($199)	($184)	($201)	($584)
Adjusted Capex Target	**$396**	**$218**	**$241**	**$231**	**$1,086**
Actual/Forecasted Capex	**$474**	**$277**	**$153**	**$141**	**$1,045**

To stay within the authorized revenue requirement and because SDG&E exceeded its capital expenditures in 2024, it is necessary to reduce SDG&E's wildfire mitigation spending for 2025, 2026, and 2027. The changes to WMP targets for 2024 and 2025 as proposed in this Petition to Amend support alignment with the costs authorized in SDG&E's GRC and should be approved as consistent with the Petition to Amend Guidelines.

II. Requested Changes to 2024 Initiatives

a. Distribution Communications Reliability Improvements (WMP.549); p. 175, SDG&E 2023-2025 Base WMP

SDG&E requests to reduce the 2024 target for this program from 60 base stations to 5 base stations. To find cost efficiencies without increasing wildfire risk and consider affordability measures given the GRC and to align with the pending Settlement Agreement, SDG&E elected to transition from a high-volume deployment of this program to a more targeted deployment while continuing to assess the benefit of this program and where additional efficiencies could be achieved through refined practices and alternative technology. In light of SDG&E's final 2024 GRC Decision, SDG&E is also requesting changes to this program for 2025.

This change will result in a delay to some of the communications reliability improvements expected from the SDG&E-owned private LTE network that supports some of SDG&E's Advanced Protection Programs (APP), including Falling Conductor Protection (FCP) and Early Fault Detection (EFD). FCP and EFD work will continue to be deployed on this new network where available, and will utilize alternate technologies for support when necessary.

b. Standby Power Program (Fixed Backup Power) (WMP.468); p. 181, SDG&E 2023-2025 Base WMP

SDG&E requests to reduce the 2024 target for this program from 300 generators to 58 generators. To find cost efficiencies without increasing wildfire risk and consider affordability measures given the pending GRC, and to align with the pending Settlement Agreement, SDG&E elected to scale back on the scope of this program. Further, because there were no PSPS de-energizations from 2021 to mid-2024, no new customers had been added to the scope of the program. SDG&E will continue to explore additional PSPS mitigation approaches for its customers and expects this program to evolve in the 2026-2028 WMP cycle.

c. Drone Assessments (WMP.552); p. 202, SDG&E 2023-2025 Base WMP

SDG&E requests to reduce the 2024 target for this program from 13,500 inspections to 6,500 inspections. To find cost efficiencies without increasing wildfire risk and consider affordability measures given the pending GRC, and to align with the pending Settlement Agreement, SDG&E reevaluated the program to optimize the number of inspections based on further risk assessment. This reevaluation aimed to balance expected risk reduction with expected repair and replacement costs and timelines. The historical number and severity of findings from the first year of program implementation (2023), along with historical repair and replacement costs, were evaluated against the expected wildfire risk consequences at each asset location. This resulted in a determination to perform 6,500 inspections, which represented a balanced approach that still maximized risk reduction. The number of inspections may be adjusted to reduce wildfire risk based on the results of any given year. SDG&E will provide additional information on program updates in subsequent WMP filings.

d. Distribution Infrared Inspections (WMP.481); p. 195, SDG&E 2023-2025 Base WMP

SDG&E requests to reduce the 2024 target for this program from 9,532 inspections to 300 inspections. To find cost efficiencies without increasing wildfire risk and consider affordability measures given the pending GRC, and to align with the pending Settlement Agreement, SDG&E transitioned this program to a risk-informed approach in an effort to optimize outcomes. In prior years, structures selected for this program were based on previous inspections, to ensure inspections were not repeated in consecutive years, and were informed by subject matter expert recommendations. However, SDG&E found that this inspection program yielded only a 0.2 percent find rate. To optimize the program for 2024, specific areas were targeted during peak load season and structures were selected using a risk-informed strategy comprised of SDG&E's Asset 360 models, risk analytics models, and Intelligent Image Processing (IIP). This program will continue with the risk-informed approach in 2025, and inspections will be performed on 300 structures, as approved in SDG&E's 2025 WMP Update.

e. Fuels Management (WMP.497); p. 276, SDG&E 2023-2025 Base WMP

SDG&E requests to reduce the 2024 target for this program from 500 poles to 150 poles. To find cost efficiencies without increasing wildfire risk, consider affordability measures, and to align with the pending Settlement Agreement, SDG&E elected to reduce the scope of this program in 2024. The reduced scope of the program is supported by the reduction to SDG&E's vegetation management forecasts authorized by SDG&E's GRC Decision.[14]

[14] *D.24-12-074 at 488-489.*

III. Requested Changes to 2025 Initiatives

SDG&E proposes necessary changes for its 2025 system hardening initiatives and resulting changes to the targets for these programs. The driver of these changes is the need to align SDG&E's Base WMP with the regulatory guidance and revenue requirement authorized in SDG&E's final GRC Decision.[15] Upon receiving its final GRC Decision and aligning its grid hardening strategy accordingly, SDG&E reviewed the remaining WMP portfolio of initiatives to identify where it could realize cost alignment with authorized funding and prioritize risk reduction. SDG&E proposes the following amendments to its 2025 WMP targets based on the results of that review and as part of an ongoing effort to refine SDG&E's grid hardening strategy. Updated system hardening miles are based on SDG&E's current business planning forecasts and informed by prior work completed during this GRC cycle.

a. Strategic Undergrounding (WMP.473); p. 158, SDG&E 2023-2025 Base WMP

Given the level of funding and discussion provided in the final GRC decision, SDG&E requests to reduce the 2025 target for this program from 125 miles to 28 miles, which will complete the amount of work authorized in its GRC decision. SDG&E continues to explore options regarding ongoing implementation of its 2024 GRC and further opportunities for risk reduction and will provide additional updates in its 2026-2028 Base WMP as well as future WMP filings.

b. Covered Conductor (WMP.455); pg 156, SDG&E 2023-2025 Wildfire Mitigation Plan

SDG&E requests to increase the 2025 target for this program from 40 miles to 50 miles for 2025. Consistent with its GRC Decision,[16] SDG&E is exploring options to increase covered conductor deployment throughout the remainder of its rate case cycle and therefore intends to install covered conductor at a faster rate than initially anticipated. SDG&E's current covered conductor scope considers wildfire and PSPS risk at the circuit segment level and the effectiveness of both covered conductor and undergrounding as mitigation alternatives. The current scope for this program in its entirety is approximately 300 miles. Between 2020 and 2024, SDG&E installed approximately 168 miles and expects to install as much of the remaining scope as possible by 2027 year-end beginning with 50 miles in 2025.

SDG&E further notes that its GRC decision did not authorize cost recovery for covered conductor projects in alignment with SDG&E's program forecasts.[17] SDG&E is in the process of evaluating its grid hardening strategy, including covered conductor deployment, as it continues to enhance its risk models, develop its methodology for cost/benefit analysis, and understand the effectiveness of its mitigations for both wildfire and PSPS de-energizations in the context of an evolving climate. In addition, expansion of existing covered conductor scope may be delayed due to the time it takes to expand scoped mileage,

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[15] *See D.24-12-074 at 479-483.*
[16] *Id. at 990, Finding of Fact 173.*
[17] *Id. at 990, Finding of Fact 174.*

including additional work to obtain permits, acquire easements, complete design, and complete construction.

c. Strategic Pole Replacement Program (WMP.1189); p. 179 SDG&E 2023-2025 WMP

To further align WMP programs with SDG&E's GRC, SDG&E requests to reduce the 2025 target for this program from 291 poles to 200 poles. SDG&E is not descoping work for this program; rather, it is extending the timeframe for which it will complete the scoped work as discussed in its 2026-2028 Base WMP.

d. Lightning Arrester Removal/Replacement (WMP.550), Avian Protection (WMP.972), Expulsion Fuse Replacements (WMP.459), Connectors including Hotline Clamps (WMP.464); p. 222, SDG&E 2023-2025 WMP

To further align WMP programs with SDG&E's GRC, SDG&E requests to reduce the 2025 targets for these asset replacement programs to 90 lightning arrestors, 100 hotline clamps, 95 poles with avian protection, and 80 fuses. Going forward, rather than proactive, high-volume deployment of these assets, SDG&E will strategically deploy these assets with the deployment of covered conductor and continue to replace them as needed as part of its Corrective Maintenance Program (CMP). This deployment plan will achieve cost efficiencies and prioritize higher risk circuit segments in tandem with covered conductor. Given the limited period of time between issuance of SDG&E's final GRC Decision and submission of this Petition to Amend, SDG&E has not performed a comprehensive assessment of new targets for these initiatives. There are several variations in covered conductor deployment that must be accounted for in order to determine targets; SDG&E has made its best effort to estimate targets based on an average number of poles per circuit mile.

e. Transmission OH Hardening (WMP.543); p. 164, SDG&E 2023-2025 WMP

SDG&E requests to reduce the 2025 target for this program from 4.64 miles to 2 miles. This reduction is due to a dependency on distribution underbuild that was previously scoped for strategic undergrounding but will no longer be performed in 2025 due to the undergrounding program reductions described in Section III b. Therefore, the transmission hardening work requires either a re-design to account for the distribution underbuild or will be shifted to future years when the distribution underbuild is undergrounded.

f. Distribution Communications Reliability Improvements (WMP.549); p. 175, SDG&E 2023-2025 Base WMP

To further align WMP programs with funding totals authorized by SDG&E's GRC, SDG&E requests to reduce the 2025 target from 42 to 5 base stations in an effort to realize cost efficiencies aligned with its GRC decision. This program has no direct impact to risk reduction and therefore will not change SDG&E's risk profile. Additional information on this program is provided Section II a.

g. Microgrids (WMP.462); p. 167, SDG&E 2023-2025 Base WMP

While SDG&E is not requesting a target change in 2025 for this program, it notes that the renewable generation and battery storage components of its remaining microgrids will be suspended until funding is secured. The microgrids are operational and capable of serving customers during a PSPS de-energization utilizing traditional generation and therefore the intent of reducing PSPS impacts on customers has been achieved.

h. Drone Assessments (WMP.552); p. 202, SDG&E 2023-2025 Base WMP

SDG&E requests to reduce the 2025 target from 13,500 inspections to 6,500 inspections in an effort to realize cost efficiencies aligned with its GRC decision, as described in Section II c.

i. Detailed Vegetation Inspections (WMP.494); p. 268, SDG&E 2023-2025 Base WMP

SDG&E requests to reduce the 2025 target for this program from 485,400 inspections to 255,000 inspections, which reflects inspections performed in High Fire Threat District (HFTD) portions of its service territory, consistent with the approach taken in SDG&E's GRC Decision.[18] Further, as SDG&E's WMP reporting is otherwise largely dedicated to work performed in the HFTD, this revision brings the target in line with other WMP programs and initiatives. The proposed change does not result in any reductions to SDG&E's vegetation management program.

j. Pole Clearing (WMP.512); p. 278, SDG&E 2023-2025 Base WMP

To further align WMP initiatives with approved GRC funding, SDG&E requests to reduce the 2025 target for this program from 33,010 poles to 22,000 poles. Beginning in 2025, SDG&E will no longer include poles that are exempt from Public Resources Code (PRC) § 4292 in this program, as these poles include hardware on CAL FIRE's list of equipment exempt from pole clearing requirements in PRC § 4292.

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[18] *D.24-12-074 at 991, Finding of Fact 179.*

Attachment A: Revised Initiative Targets and Projected Capital and O&M Expenditure Chart

Attachment B: Redlines to Affected Portions of 2023-2025 Base WMP

Attachment A- Revised Initiative Targets and Projected Capital and O&M Expenditures

			Projected 2025 WMP Update					Projected 2025 Revised				
			CAPEX ($000)		OPEX ($000)		Target	CAPEX ($000)		OPEX ($000)		Target
WMP Initiative Activity	Tracking ID	Initiative Name	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	
Public outreach and education awareness program	WMP.527		$0	$0	$4,004	$4,004	n/a	$0	$0	$605	$605	n/a
Engagement with access and functional needs populations	WMP.532		$0	$0	$0	$0	n/a	$0	$0	$1,719	$1,719	n/a
Public emergency communication strategy	WMP.1198		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Collaboration on local wildfire mitigation planning	WMP.1199		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Best practice sharing with other utilities	WMP.1200		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Collaboration on local wildfire mitigation planning	WMP.1337	Community Engagement	$0	$0	$641	$641	n/a	$0	$0	$0	$0	n/a
Other	WMP.514	Crew-accompanying ignition prevention and suppression resources and services	$0	$0	$3,836	$3,836	n/a	$0	$0	$4,500	$4,500	n/a
Personnel Work Procedures and Training in Elevated Fire Risk (Grid Ops)	WMP.557	Aviation Firefighting Program	$689	$689	$8,366	$8,366	n/a	$3,109	$689	$5,171	$5,171	n/a
Public emergency communication strategy	WMP.563		$7,757	$7,757	$5,219	$5,219	n/a	$9,154	$7,757	$8,706	$8,706	n/a
Customer support in wildfire and PSPS emergencies	WMP.1007		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Emergency preparedness plan	WMP.1008		$315	$315	$16,148	$16,148	n/a	$410	$315	$21,720	$21,720	n/a
Preparedness and planning for service restoration	WMP.1009		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
External collaboration and coordination	WMP.1201		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Grid Response Procedures and Notifications (Grid Ops)	WMP.449	Wireless Fault Indicators	$0	$0	$0	$0	0	$0	$0	$0	$0	0
Other grid topology improvements to minimize risk of ignitions	WMP.453	Capacitor Maintenance and replacement program (SCADA)	$0	$0	$0	$0	0	$0	$0	$0	$0	0

			Projected 2025 WMP Update					Projected 2025 Revised				
			CAPEX ($000)		OPEX ($000)		Target	CAPEX ($000)		OPEX ($000)		Target
WMP Initiative Activity	Tracking ID	Initiative Name	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	
Covered conductor installation	WMP.455	Covered Conductor	$67,632	$67,632	$3,090	$3,090	40	$81,431	$81,431	$2,042	$2,042	**50**
Equipment inspections, maintenance, and repair	WMP.459	Expulsion fuse replacement	$1,550	$1,550	$0	$0	700	$0	$0	$0	$0	**80**
Equipment inspections, maintenance, and repair	WMP.464	Maintenance, repair, and replacement of connectors, including hotline clamps	$1,702	$1,451	$52	$44	950	$0	$0	$0	$0	**100**
Equipment inspections, maintenance, and repair	WMP.550	Lightning arrester removal and replacement	$3,483	$3,483	$0	$0	1,848	$0	$0	$0	$0	**90**
Other grid topology improvements to minimize risk of ignitions	WMP.972	Avian Protection	$1,512	$1,210	$10	$8	200	$0	$0	$0	$0	**95**
Other grid topology improvements to minimize risk of ignitions	WMP.1189	Strategic Pole Replacement Program	$6,948	$6,948	$4	$4	291	$7,923	$7,923	$303	$303	**200**
Other technologies and systems not listed above	WMP.461	PSPS Sectionalizing Enhancements	$1,881	$1,881	$0	$0	10	$1,485	$1,485	$0	$0	10
Microgrids	WMP.462	Microgrids	$14,127	$0	$1,445	$0	0	$0	$0	$1,236	$0	0
Other technologies and systems not listed above	WMP.466	Generator Grant Program	$0	$0	$3,233	$3,233	n/a	$0	$0	$3,953	$3,953	n/a
Other technologies and systems not listed above	WMP.467	Generator Assistance Program	$0	$0	$501	$501	n/a	$0	$0	$494	$494	n/a
Other technologies and systems not listed above	WMP.468	Standby Power Programs	$0	$0	$5,539	$5,539	89	$0	$0	$1,000	$1,000	89
Traditional overhead hardening	WMP.1016	CNF (Distribution Underground)	$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Traditional overhead hardening	WMP.1017	CNF (Distribution Overhead)	$648	$648	$155	$155	n/a	$648	$648	$231	$231	n/a
Distribution pole replacements and reinforcements	WMP.458		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Transmission pole/tower replacements and reinforcements	WMP.472		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Undergrounding of electric lines and/or equipment	WMP.473	Strategic Undergrounding	$358,877	$358,877	$1,709	$1,709	125	$85,728	$85,728	$1,493	$1,493	**28**
Traditional overhead hardening	WMP.475	Distribution OH System Hardening	$1,078	$1,078	$963	$963	0	$2,800	$2,800	$3,150	$3,150	0
Traditional overhead hardening	WMP.543	Transmission OH Hardening	$0	$0	$0	$0	4.64	$0	$0	$0	$0	**2**
Traditional overhead hardening	WMP.545	Transmission OH Hardening - Distribution Underbuild	$14,694	$14,694	$4	$4	1.8	$3,500	$3,500	$1	$1	1.8

			Projected 2025 WMP Update					Projected 2025 Revised				
			CAPEX ($000)		OPEX ($000)		Target	CAPEX ($000)		OPEX ($000)		Target
WMP Initiative Activity	Tracking ID	Initiative Name	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	
Installation of system automation equipment	WMP.463	Advanced Protection	$3,383	$3,383	$207	$207	8	$8,010	$8,010	$145	$145	8
Installation of system automation equipment	WMP.1195	Early Fault Detection	$3,410	$3,410	$4	$4	60	$4,292	$4,292	$127	$127	60
Installation of system automation equipment	WMP.549	Distribution Communications Reliability Improvements	$43,213	$42,184	$999	$975	42	$8,700	$8,700	$2,287	$2,233	**5**
Line removals (in HFTD)	WMP.1202		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Asset inspections	WMP.478	Distribution overhead detailed inspections	$9,563	$9,563	$824	$824	13,275	$9,563	$9,563	$494	$494	13,275
Asset inspections	WMP.479	Transmission overhead detailed inspections	$1,943	$1,943	$38	$38	2,479	$1,943	$1,943	$15	$15	2,479
Asset inspections	WMP.481	Distribution infrared inspections	$0	$0	$10	$0	300	$0	$0	$5	$5	300
Asset inspections	WMP.482	Transmission infrared inspections	$0	$0	$0	$0	7,331	$0	$0	$0	$0	7,331
Asset inspections	WMP.483	Distribution wood pole intrusive inspections	$1,462	$1,462	$104	$104	344	$1,462	$1,462	$79	$79	344
Asset inspections	WMP.484		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Asset inspections	WMP.488	Distribution overhead patrol inspections	$875	$875	$313	$313	86,535	$875	$875	$309	$309	86,535
Asset inspections	WMP.489	Transmission overhead patrol inspections	$0	$0	$0	$0	7,533	$0	$0	$0	$0	7,533
Asset inspections	WMP.492	Substation patrol inspections	$0	$0	$0	$0	384	$0	$0	$0	$0	384
Asset inspections	WMP.551		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Asset inspections	WMP.552	Drone assessments	$54,937	$53,289	$31,490	$30,545	13,500	$32,936	$32,936	$16,692	$16,692	**6,500**
Asset inspections	WMP.555	Transmission 69kV tier 3 visual inspections	$0	$0	$0	$0	1,632	$0	$0	$0	$0	1,632
Asset inspections	WMP.1190	Transmission wood pole intrusive inspections	$0	$0	$0	$0	114	$0	$0	$0	$0	114
Quality assurance / quality control	WMP.491	QA/QC of Distribution Detailed Inspections	$0	$0	$0	$0	50%	$0	$0	$0	$0	50%
Quality assurance / quality control	WMP.1191	QA/QC of Transmission Inspections	$0	$0	$0	$0	100%	$0	$0	$0	$0	100%
Quality assurance / quality control	WMP.1192	QA/QC of Distribution Drone Assessments	$0	$0	$0	$0	100%	$0	$0	$0	$0	100%
Quality assurance / quality control	WMP.1193	QA/QC of Wood Pole Intrusive (Transmission & Distribution)	$0	$0	$0	$0	10%	$0	$0	$0	$0	10%
Quality assurance / quality control	WMP.1194	QA/QC of Substation Inspections	$0	$0	$0	$0	18	$0	$0	$0	$0	18
Open work orders	WMP.1203		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Equipment Settings to Reduce Wildfire Risk (Grid Ops)	WMP.1204		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Grid Response Procedures and Notifications (Grid Ops)	WMP.1205		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a

			Projected 2025 WMP Update					Projected 2025 Revised				
			CAPEX ($000)		OPEX ($000)		Target	CAPEX ($000)		OPEX ($000)		Target
WMP Initiative Activity	Tracking ID	Initiative Name	Territory	HFTD	Territory	HFTD		Territory	HFTD	Territory	HFTD	
Workforce Planning	WMP.1206		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Personnel Work Procedures and Training in Conditions of Elevated Fire Risk (Grid Ops)	WMP.515		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Environmental compliance and permitting	WMP.493		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Environmental monitoring systems	WMP.447		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Environmental monitoring systems	WMP.970		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Environmental monitoring systems	WMP.1431	Air Quality Station Maintenance	$0	$0	$74	$74	16	$0	$0	$84	$84	16
Environmental monitoring systems	WMP.1430	Weather Station Maintenance and Calibration	$140	$140	$0	$0	216	$261	$261	$0	$0	216
Weather forecasting	WMP.443		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Fire potential index	WMP.450		$1,477	$1,477	$4,366	$4,366	n/a	$0	$0	$4,538	$4,538	n/a
Other technologies and systems not listed above	WMP.558		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Vegetation Inspections	WMP.494		$0	$0	$61,887	$32,639	485,400	$0	$0	$58,503	$30,854	**255,000**
Emergency response vegetation management	WMP.496		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Wood and slash management	WMP.497	Fuels Management	$0	$0	$6,008	$6,008	500	$0	$0	$5,445	$5,445	500
Clearance	WMP.501		$0	$0	$10,542	$10,542	11,200	$0	$0	$10,542	$10,542	11,200
Quality assurance / quality control	WMP.505		$0	$0	$0	$0	15%	$0	$0	$0	$0	15%
Vegetation management enterprise system	WMP.511		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Pole clearing	WMP.512		$0	$0	$8,130	$7,145	33,010	$0	$0	$6,427	$5,648	**22,000**
Open work orders	WMP.1207		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Workforce Planning	WMP.1208		$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
High-risk species	WMP.1325	Right Tree Right Place	$0	$0	$1,030	$1,030	n/a	$0	$0	$0	$0	n/a
High-risk species	WMP.1326	Community Tree Rebate Program	$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Asset management and inspection enterprise system(s)	WMP.519	Centralized repository for data	$15,331	$15,331	$1,688	$1,688	n/a	$8,504	$8,504	$2,020	$2,020	n/a
Risk Methodology and Assessment	WMP.442	A summarized risk map that shows the overall ignition probability and estimated wildfire	$0	$0	$3,436	$3,436	n/a	$3,974	$3,974	$5,754	$5,754	n/a

			Projected 2025 WMP Update					Projected 2025 Revised				
			CAPEX ($000)		OPEX ($000)		Target	CAPEX ($000)		OPEX ($000)		Target
WMP Initiative Activity	**Tracking ID**	**Initiative Name**	**Territory**	**HFTD**	**Territory**	**HFTD**		**Territory**	**HFTD**	**Territory**	**HFTD**	
		consequence along the electric lines and equipment (WiNGS)										
Other	WMP.521	Documentation and disclosure of wildfire-related data and algorithms	$0	$0	$0	$0	n/a	$0	$0	$0	$0	n/a
Other	WMP.523	Allocation methodology development and application	$1,106	$1,106	$5,524	$5,524	n/a	$0	$0	$5,045	$5,045	n/a
TOTAL			**$619,734**	**$602,376**	**$191,590**	**$158,924**		**$276,707**	**$272,796**	**$174,835**	**$145,117**	
TOTAL CAPEX + OPEX **Projected $811,323** **Revised $451,542**												

4 Overview of WMP

4.1 Primary Goal

In accordance with California Public Utilities Code (PUC) § 8386(a), an electrical corporation must satisfy the following primary goal:

> *Each electrical corporation shall construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment.*

In accordance with PUC § 8386(a), SDG&E constructs, maintains, and operates its electric system in a manner that minimizes the risk of catastrophic wildfire posed by its electric power lines and equipment. Building on over 10 years of wildfire prevention and mitigation work, the 2023-2025 WMP continues to focus on reducing wildfire risk and reducing the impact of Public Safety Power Shutoff (PSPS) events on customers. Each year, SDG&E identifies ways to improve its wildfire prevention and mitigation efforts through enhancing or expanding existing programs and developing and implementing new efforts. Three-year and ten-year objectives for each category are described in Section 4.2 Plan Objectives.

4.2 Plan Objectives

4.2.1 Risk Methodology and Assessment

SDG&E continues to explore opportunities to enhance its risk models to improve its analytics capabilities and further utilize its models to inform decision-making. A risk modeling improvement plan has been developed that includes evaluation of additional factors in risk models such as social vulnerability, impacts of climate change, and further breaking out the assessment of risk drivers. Additionally, modeling design and architecture will continue to be enhanced, enabling tracking and validation of various model risk components, establishing a formalized process for conducting independent reviews, and further exploring the expanded use of models to inform selection and prioritization of initiatives other than covered conductor and undergrounding.

4.2.2 Wildfire Mitigation Strategy

SDG&E's wildfire mitigation strategy continues to evolve with the improvements and enhancements made to risk modeling and the real-world lessons learned through initiative implementation. The Wildfire Next Generation System Planning (WiNGS)-Planning model has incorporated additional inputs and refinements leading to a portfolio of approximately 1,500 miles of strategic undergrounding and 370 miles of covered conductor to be installed between 2022 and 2032. This portfolio will reduce the risk of wildfire by 83 percent and will significantly reduce the impacts of PSPS events to customers on frequently impacted circuits. This strategy will continue to be refined as new information including climate change, weather patterns, and mitigation effectiveness is studied and validated.

4.2.3 Grid Design, Operations, and Maintenance

SDG&E's grid hardening programs are aimed at reducing the risk of wildfires caused by utility equipment and minimizing impacts to customers from mitigations such as PSPS events. Programs such as the Covered Conductor Program (WMP.455) will prevent risk events from occurring across several drivers such as energized wire down and foreign object contact. SDG&E will continue to advance its covered conductor and strategic undergrounding efforts in addition to implementing specific equipment upgrades such as expulsion fuse replacements, installation of additional sectionalizing, and upgrading to supervisory control and data acquisition (SCADA) devices across the system (WMP.453). SDG&E will further advance implementation of new technologies such as Advanced Radio Frequency Sensors (ARFS) which officially kicked-off in mid-2022 after completing a 2-year demonstration. Additionally, by expanding the use and development of enhanced inspection technologies such as infrared inspections of overhead distribution (WMP.481), drone assessments (WMP.552), and Intelligent Image Processing (IIP) (WMP.1342), SDG&E will be able to detect damage and collect data on distribution and vegetation.

4.2.4 Vegetation Management and Inspections

Enhancements to the Vegetation Management Program include tracking and maintaining its asset (tree and pole) database (WMP.511) for all activities including detailed (WMP.494) and off-cycle inspection (WMP.508), trimming and removals and enhanced vegetation management (WMP.501), pole brushing (WMP.512), and auditing (WMP.505). Improvements to the work management system on the server side of the application (CitiWorks) and the mobile application (Epoch) have enabled the creation of specialized Dispatch Work Orders (DWOs) to support off-cycle patrol inspections and enhanced vegetation management. Additional data collection enhancements include the collection of inventory tree Genus-species, electronic customer refusal tracking, and additional GIS mapping layers for improved situational awareness.

4.2.5 Situational Awareness and Forecasting

The Fire Science and Climate Adaptation (FSCA) business unit continues to play a critical role in SDG&E's wildfire mitigation efforts responding to and strategizing for fire preparedness activities and climate resilience related programs. In this WMP cycle, SDG&E plans to continue technological advancements for fire science modeling and weather analysis including fully automating fire detection capabilities, exploring sensor technologies for portable monitoring in field trucks, exploring smoke plume modeling technology, and building new machine learning wind speed and gust models. Additionally, SDG&E plans to continue its partnership with academia to further develop fire science for integration into Santa Ana Wind Threat Index (SAWTI) (WMP.540) and Fire Potential Index (FPI) (WMP.450) as well as evaluate large computational resources to include a module for impact of large eddy scale weather. The creation of a Wildfire & Climate Resiliency Center (WCRC) in 2023 will also bring together leading thinkers and problem solvers in academia, government, and the community to create forward-looking solutions to help prevent ignitions, mitigate the impacts of fires, and ultimately help build a more resilient region.

4.2.6 Emergency Preparedness

As part of its commitment to continuous improvement, SDG&E has established a comprehensive After-Action Review (AAR) process that follows Emergency Operations Center (EOC) activations, which includes workshops with both internal and external stakeholders to gather lessons learned to inform any corrective actions. SDG&E plans to expand Emergency Management Operations by increasing staff dedicated to enhancing various emergency programs, modifying workforce training, streamlining processes and documentation management, improving collaboration by developing a software solution allowing for third-party access, and creating dashboards that incorporate Human Factors Engineering (HFE) into PSPS decision-making tools (WMP.1335). Emergency preparedness also entails working with community partners and stakeholders by incorporating effectiveness outreach survey feedback, expanding Tribal and Access and Functional Needs (AFN) campaigns, Community Based Organizations (CBOs) and local school districts.

4.2.7 Community Outreach and Engagement

SDG&E recognizes that collaboration, the sharing of best practices, and the exchange of lessons learned is of the utmost importance to protect public safety. In an effort to identify gaps in its processes and outreach efforts, SDG&E regularly solicits feedback from its partners and communities it serves (WMP.1337). SDG&E continues to refine and augment its year-round safety education and communication campaigns, enhancing mobile application and communication platforms, leveraging school communication platforms, and expanding public education to AFN, Limited English Proficiency (LEP) populations and Tribal communities (WMP.1336)

4.2.8 Public Safety Power Shutoff

Reducing the impacts of PSPS continues to be a core goal for SDG&E. In addition to continuing the implementation of grid hardening initiatives and resiliency programs to reduce the likelihood and consequences of PSPS for customers, SDG&E is committed to expanding its education and communication efforts related to wildfire safety to PSPS targeted customers throughout the service territory (WMP.563). Furthermore, SDG&E evaluates many factors before deciding to shutoff power by the weather network and is committed to enhancing assessment strategies to further opportunities to increase PSPS thresholds. WiNGS-Ops will evolve to assess wildfire risk and study customer impacts of PSPS events. As technology becomes more sophisticated, modeling efforts will be improved by increasing granularity and accuracy in PSPS risk assessments in WiNGS-Ops and integrating the FPI into the Network Management System (NMS) for future protective equipment threshold setting improvements (WMP.1338).

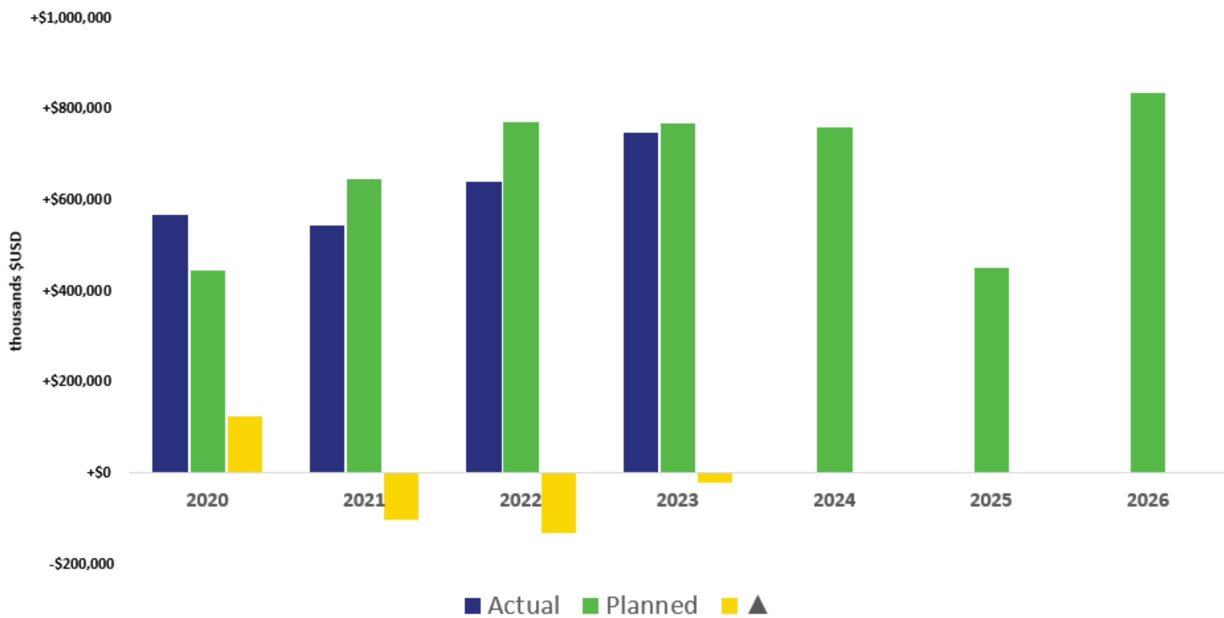
4.3 Proposed Expenditures

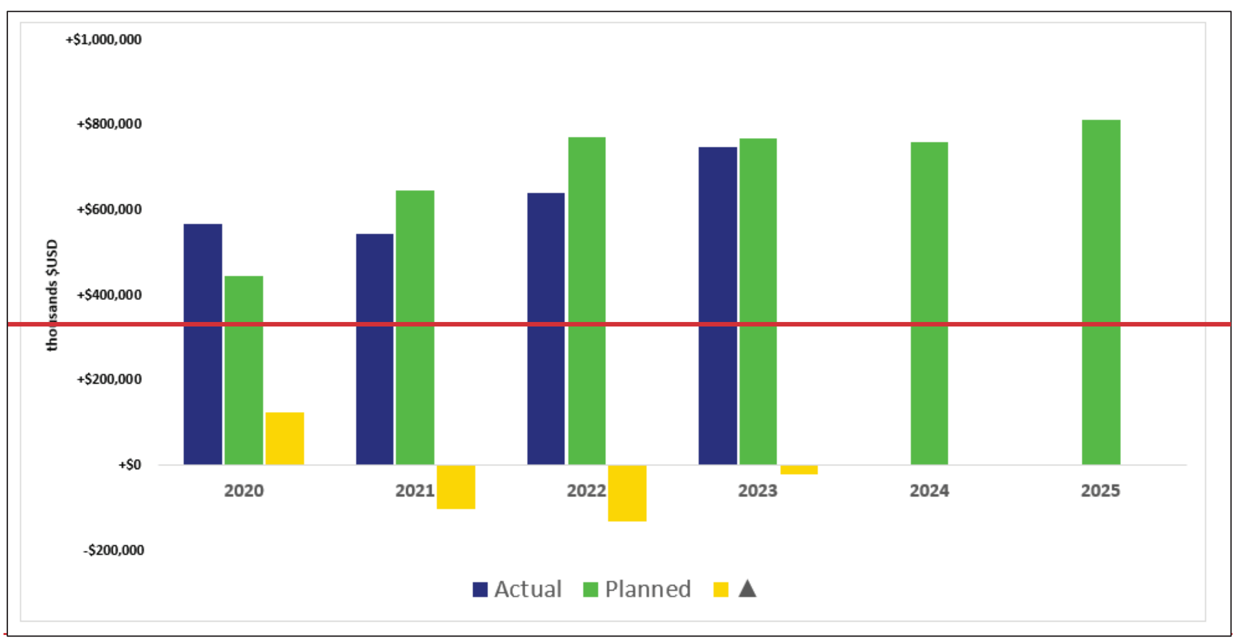
OEIS Table 4-1: Summary of WMP Expenditures

Year	Spend (thousands $USD)
2020	Planned (as reported in the 2020 WMP) = $444,544 Actual = $569,237 △ = +$124,693
2021	Planned (as reported in the 2021 WMP) = $646,466 Actual = $543,912 △ = -$102,554
2022	Planned (as reported in the 2022 WMP) = $770,393

Year	Spend (thousands $USD)
	Actual = $639,443 △ = -$130,950
2023	Planned = $769,741
2024	Planned = $760,622
2025	Planned = $451,542 ~~811,323~~

Figure 4-1: Summary of WMP Expenditures





4.4 Risk Informed Framework

This WMP is developed using SDG&E's Enterprise Risk Management Framework, which is modeled after an internationally recognized risk management standard, ISO 31000. The framework consists of an enterprise risk management governance structure. This addresses the roles of employees at various levels up to SDG&E's Board of Directors, along with various risk processes and tools. One such procedure is the enterprise risk management process, which defines enterprise goals, analyzes the service territory, identifies, manages, and mitigates enterprise risks, and provides consistent, transparent, and repeatable results.

This process is aligned with the Cycla Corporation's 10-Step Evaluation Method, which was adopted by the California Public Utilities Commission (CPUC) "as a common yardstick for evaluating maturity, robustness, and thoroughness of utility Risk Assessment and Mitigation Models and risk management frameworks."[2] While the lexicon used by Cycla differs slightly from that of SDG&E, the content is largely aligned. SDG&E initiates its enterprise risk management process annually, resulting in the Enterprise Risk Registry (ERR), an inventory of enterprise risks. The CPUC defines an ERR as "[a]n inventory of enterprise risks at a snapshot in time that summarizes (for a utility's management and/or stakeholders such as the CPUC) risks that a utility may face. The ERR must be refreshed on a regular basis and can reflect the changing nature of a risk; for example, risks that were consolidated together may be separated, new risks may be added, and the level of risks may change over time."[3]

The ERR thus presents enterprise-level risks, including safety-related and wildfire-related risks. Each risk has one or more risk owner(s)—a member of the senior management team who is ultimately responsible and accountable for the risk—and one or more risk manager(s) responsible for ongoing risk assessments and overseeing implementation of risk management plans. See Section 2 Responsible Persons.

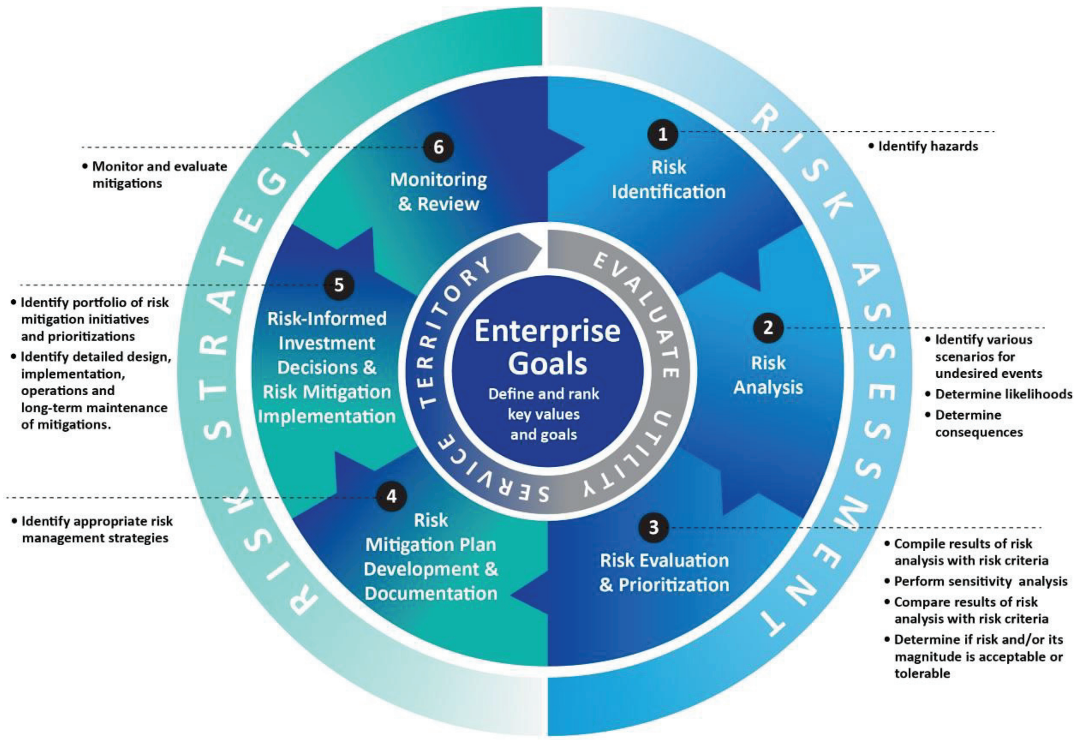
Input from risk managers and risk owners is used to ultimately finalize the ERR. Therefore, the Enterprise Risk Management Framework is both a "bottom-up" and "top-down" approach.

In addition, each risk in the ERR has an associated set of mitigations (i.e., projects or programs that reduce the likelihood of the risk and/or negative consequences should the risk occur). Notwithstanding these risk management and mitigation efforts, however, adverse events will occur. When that happens, efforts, including implementation of response plans, development of role and responsibility descriptions and checklists, and facilitation of training and exercises, are designed to prepare the Company to respond safely and effectively to those adverse events that occur despite mitigation efforts.

Figure 4-2 describes SDG&E's Enterprise Risk Management Framework.

[2] D.16-08-018 at 195, Ordering Paragraph 4.
[3] D.18-12-014 at 16-17.

Figure 4-2: Enterprise Risk Management Framework



4.4.1 Risk Assessment: Identification, Analysis, Evaluation, and Prioritization

In the Enterprise Risk Management Framework, as explained in SDG&E's 2021 Risk Assessment Mitigation Phase (RAMP),[4] risk identification is the process of finding, recognizing, and describing risks. The Enterprise Risk Management organization first works with various business units to update existing risk information and identify enterprise-level risks that have emerged or accelerated since the last assessment. This includes the identification of risk events, their causes, and potential consequences. This is then summarized in a "Risk Bow Tie" as shown in Figure 6-7: WiNGS Planning Calculation Schematic and Figure 6-8: WiNGS-Ops Calculation Schematic. The Risk Bow Tie is "[a] tool that consists of a Risk Event in the center, a listing of drivers on the left side that potentially lead to the Risk Event occurring, and a listing of Consequences on the right side that show the potential outcomes if the Risk Event occurs."[5]

The Enterprise Risk Management Framework also includes risk evaluation.[6] For the ERR, risks are evaluated using a 7 X 7 matrix with impact and frequency as the risk dimensions. The evaluation of the Enterprise risks using the 7 X 7 matrix is performed on a residual basis (i.e., after considering controls) resulting in a residual risk score. For purposes of SDG&E's 2021 RAMP filing, the methodology or framework utilized to calculate risk scores, including for Wildfire risk, was the Multi-attribute Value

[4] Application 21-05-011, Application of SDG&E to Submit its 2021 RAMP Report (May 17, 2021) (2021 RAMP), Chapter RAMP-B at B-3.
[5] D.18-12-014 at 16.
[6] See 2021 RAMP, Chapter RAMP-B at B-5 - B-6.

Function (MAVF) method adopted by the Safety Model and Assessment Proceeding (S-MAP)[7] and resulting Settlement.

The S-MAP puts forth a consistent framework to be applied in future RAMP and General Rate Case (GRC) filings for identifying and evaluating risk across all California utilities, making the Enterprise Risk Management Framework generally consistent with other utilities' approaches. Notably, SDG&E was the first utility to apply the new quantitative risk methodology adopted in the S-MAP and is continuing to review opportunities for improvement and lessons learned from the new approach, including the feedback received in the open RAMP review process.

4.4.2 Risk Strategy: Plan Development, Investment Decisions, Implementation, and Review

The WMP is developed by reviewing and understanding the risk within the service territory and identifying and prioritizing mitigations to address that risk. Information on the service territory is gathered through the use of weather stations, equipment failure reporting, and other means and is able to draw upon over a decade's worth of data. The mitigations within this WMP are developed utilizing information currently available to subject matter experts and are continuously reviewed and updated as new information becomes available.

SDG&E's initial plans were based on the known risk drivers and consequence information available over 10 years ago. For example, SDG&E's initial distribution overhead hardening program targeted the locations of small wire which was known to have a higher failure rate. Hardening was performed only on locations with the riskiest wire. It was prioritized based on location information such as the High-Risk Fire Area (HRFA) and Fire Threat Zones (FTZ) that predated the HFTD and the initial implementation of the Wildfire Risk Reduction Model (WRRM). Similarly, asset replacement programs such as fuse replacements and hot line clamps prioritized locations based on consequence risk by prioritizing assets in Tier 3 of the HFTD before moving into Tier 2.

SDG&E's mitigation efforts are now informed by evolving risk models that utilize more granular analysis at the circuit segment level. SDG&E has transitioned to hardening full segments, not partial ones, to achieve full risk reduction along with additional PSPS benefits. The WINGS-Planning model is consistently updated and improved with the latest information on both the risk of wildfire within the service territory and evolving data on the cost and efficacy of installing covered conductor and strategic undergrounding of electric lines. The modeling provides insight into how wildfire and PSPS risk reduction can be achieved across the service territory to protect the safety of customers and the environment, while maintaining reliability and affordability for ratepayers. The modeling results are reviewed by subject matter experts to provide real-world expertise on the feasibility of performing the chosen mitigation (installing covered conductor or undergrounding) considering constraints such as environmental concerns, geography, and community impacts.

Other SDG&E areas are also beginning to rely on risk models to improve programs. For example, SDG&E's distribution infrastructure inspections are moving to performing risk-based inspections. Following the success utilizing drones for inspections within the HFTD over the past 3 years, the time-based HFTD Tier 3 inspections will be replaced with drone inspections performed on the riskiest

[7] D.18-12-014

structures within the HFTD. Structures where inspections are likely to have the biggest impact will be identified with a newly created risk. Similarly, the Vegetation Management Program will pursue the use of newly developed risk models to identify areas with the greatest risk and the prioritization of secondary inspections on these areas to be performed by the end of Q3 (September).

As new information or technology becomes available, new mitigations can be proposed by stakeholders throughout the company. New ideas and initiatives are obtained through collaborating with regulators and other utilities, evaluating risk event trends, and reviewing emerging technology. Each proposed mitigation is reviewed for feasibility and its potential costs and benefits before being approved and implemented.

Mitigations are reviewed throughout the year to understand if initiatives are achieving risk reduction targets, and the actual and forecasted costs for the year are also reviewed. Internal metrics dashboards are updated weekly to ensure all employees have visibility into the progress of wildfire mitigation initiatives. The estimated and recorded efficacy of risk-reducing mitigations are also reviewed using real-world information as it becomes available. This information will inform what changes, if any, are required for a specific mitigation or the portfolio. For example, as the per-mile costs of undergrounding has continued to reduce and the reduction of PSPS impacts are further considered, SDG&E's risk modeling now recommends more mileage of undergrounding as compared to installing covered conductor.

SDG&E strives to provide clear and transparent decision-making processes as shown in its participation and collaboration in workshops, joint utility working groups, and throughout this WMP. SDG&E will continue to take feedback and make improvements based on guidance and lessons learned from Energy Safety, other utilities, and various other stakeholders.

OEIS Table 4-2demonstrates the alignment of SDG&E's Enterprise Risk Management Framework with the risk-informed framework established by Energy Safety in the 2023-2025 WMP Technical Guidelines.[8]

OEIS Table 4-2: Risk-Informed Approach Components

Component	Component Description	SDG&E Risk Management Process	WMP Section
1. Goals and plan objectives	Identify the primary goal(s) and plan objectives of the electrical corporation's WMP.	Enterprise Goals	4.1 4.2
2. Scope of application	Define the physical characteristics of the system in terms of its major elements: electrical corporation service territory characteristics, electrical infrastructure, wildfire environmental settings, and various assets-at-risk. Knowledge and understanding of how individual system elements interface are essential to this step.	Evaluate Service Territory	5.1
3.Hazard Identification	Identify hazards and determine their likelihoods.	1. Risk Identification	6.2.1
4. Risk Scenario identification	Develop risk scenarios that could lead to an undesirable event. Risk scenario techniques that may be employed include event tree	2. Risk Analysis	6.3

[8] Office of Energy Infrastructure Safety, 2023-2025 Wildfire Mitigation Plan Technical Guidelines (December 6, 2022), available at https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=53286&shareable=true.

Component	Component Description	SDG&E Risk Management Process	WMP Section
	analysis, fault tree analysis, preliminary hazard analysis, and failure modes and effects analysis.		
5. Risk analysis	Evaluate the likelihood and consequences of the identified risk scenarios to understand the potential impact on the desired goal(s) and plan objectives. The consequences are based on an array of risk components that are fundamental to overall utility risk, wildfire risk, and PSPS risk given the electrical corporation's scope of application and portfolio of wildfire mitigation initiatives.	2. Risk Analysis	6.2.2
6. Risk presentation	Consider how the risk analysis is presented to the various stakeholders involved.	3. Risk Evaluation & Prioritization	6.4
7. Risk evaluation	Identify criteria and procedures for identifying critical risk both spatially and temporally. Risk evaluation must also include, as a minimum, evaluating the seriousness, manageability, urgency, and growth potential of the wildfire hazard/risk. Risk evaluation should be used to determine whether the individual hazard/risk should be mitigated. Risk evaluation and risk-informed decision making should be done using a consensus approach involving a range of key stakeholder groups.	3. Risk Evaluation & Prioritization	7.1
8. Risk mitigation and management	Identify which risk management strategies are appropriate given practical constraints such as limited resources, costs, and time. The electrical corporation must indicate the high-level risk management approach, as determined in Step 7.	4. Risk Mitigation Plan Development & Documentation	7.2
8. Risk mitigation and management	Identify risk mitigation initiatives (or a portfolio of initiatives) and prioritize their spatial and temporal implementation. This step includes consideration of what risk mitigation strategies are appropriate and most effectively meet the intent of the WMP goal(s) and plan objectives, while still in balance with other performance objectives. Include the procedures and strategies to develop, review, and execute schedules for implementation of mitigation initiatives and activities	5. Risk-Informed Investment Decisions & Risk Mitigation Implementation	8 9
	Monitor and evaluate mitigations. Determine effectiveness of plan to inform ongoing risk management.	6. Monitoring & Review	10 11 12

8 Wildfire Mitigations

8.1 Grid Design, Operations, and Maintenance

Once a risk mitigation plan is developed and documented, SDG&E uses a comprehensive approach to identify a portfolio of risk mitigation initiatives. This includes identification of detailed design, implementation, operations, and long-term maintenance of mitigations. The fifth step of the Enterprise Risk Management Framework is Risk-Informed Investment Decisions & Risk Mitigation Implementation (see Figure 8-1). See Section 4.4 Risk Informed Framework for details on the Enterprise Risk Management Framework. "

Figure 8-1: Risk-Informed Investment decision & Risk Mitigation Implementation Step of the Enterprise Risk Management Framework

8.1.1 Overview

SDG&E's grid hardening programs are aimed at reducing the risk of wildfires caused by utility equipment and minimizing impacts to customers from mitigations such as PSPS. Programs such as the Covered Conductor Program (WMP.455) will prevent risk events from occurring across several drivers like energized wire down and foreign object contact. Other programs such as Protection and equipment programs including advanced protection, the Expulsion Fuse Replacement Program (WMP.459), and the Lightning Arrester Program (WMP.550) do not prevent risk events from occurring, but instead reduce the chance that a risk event will result in an ignition by utilizing protection settings and/or equipment that addresses a specific failure mode known to lead to the ignition. Other programs reduce PSPS impacts to customers, including the PSPS Sectionalizing Program (WMP.461), installation of microgrids (WMP.462), and generator programs. Strategic undergrounding—a system hardening effort—reduces the need for mitigations such as PSPS while also reducing the risk of utility-caused wildfires. SDG&E's grid hardening programs, operations, and maintenance programs have contributed significantly to the Company earning the ReliabilityOne® Award for "Outstanding Reliability Performance" among utilities in the West for 17 consecutive years.

8.1.1.1 Objectives

OEIS Table 8-1: Grid Design, Operations, and Maintenance Objectives (3-year plan)

Objective Number	Objectives for Three Years (2023–2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.1.01	Continue to provide fixed backup power solutions to residential and commercial customers who experience frequent PSPS.	Standby Power Programs; WMP.468	Transmission standard practice (confidential)	Third-party data submission	12/31/2025	8.1.2.11.2, p. 181.
8.1.02	Continue to provide portable backup power solutions to vulnerable, electricity-dependent customers.	Generator Grant Program; WMP.466	Transmission standard practice (confidential)	Third-party data submission	12/31/2025	8.1.2.11.3, p. 184
8.1.03	Continue to provide rebates on portable backup power solutions to customers who experience PSPS.	Generator Assistance Program; WMP.467	Transmission standard practice (confidential)	Third-party data submission	12/31/2025	8.1.2.11.4, p. 185
8.1.04	Build 185 Base Stations to deploy a privately-owned LTE network	Distribution Communications Reliability Improvements; WMP.549	IEEE 802	Completed work orders/Primavera P6 Site Schedule.	12/31/2033	8.1.2.8.3, p. 175
8.1.05	Install avian protection equipment on distribution poles in HFTD	Avian Protection; WMP.972	• SDG&E Overhead Construction Standard (OHCS) 1600 • Migratory Bird Treaty Act • Bald and Golden Eagle Protection Act • Codes defined by California Department of Fish and Game	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.10.1, p. 178
8.1.06	Replace existing non-SCADA Capacitors with a more modern SCADA switchable Capacitor or remove non-SCADA Capacitor if not required for voltage or reactive support, to reduce potential for	Capacitor Maintenance and Replacement Program; WMP.453	• GO 95 • SDG&E OHCS 1320 • SDG&E OHCS 1325	Completed work orders/ GIS Data Submission(s)	12/31/2025	8.1.4.3, p. 221

Objective Number	Objectives for Three Years (2023–2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
	fire caused by faulted capacitors in the HFTD and WUI Areas					
8.1.07	Install new CAL FIRE-approved power fuses to replace existing expulsion fuse equipment in the HFTD.	Expulsion Fuse Replacement; WMP.459	• GO 95 • SDG&E OHCS 1207	Completed work orders/ GIS Data Submission(s)	12/31/2025	8.1.4.4, p. 222
8.1.08	Replace HLC connections that are connected directly to overhead primary conductors with compression connections	Maintenance, repair, and replacement of connectors, including hotline clamps; WMP.464	• GO 95 • SDG&E OHCS 788	Completed work orders/ GIS Data Submission(s)	12/31/2028	8.1.4.5, p. 224
8.1.09	Install CAL FIRE-approved lightning arresters in the HFTD	Lightning arrester removal and replacement; WMP.550	• GO 95 • SDG&E OHCS 1247	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.4.6, p. 226
8.1.10	Install switches in strategic locations improving the ability to isolate high-risk areas for potential de-energizations and minimize PSPS exposure to customers	PSPS Sectionalizing Enhancements; WMP.461	• GO 95 • PU Code Section 451	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.11.1, p. 181
8.1.11	Test devices that have been installed and identify the devices that do not have sufficient signals and low batteries, so they can be replaced in 2024 and 2025 by new material/WFI devices.	Wireless fault indicators; WMP.449	• GO 95 • SDG&E Electric Standard Practice (ESP) 322 • SDG&E OHCS 1276.1	Completed work orders/ GIS Data Submission(s)	12/31/2028	8.3.3, p. 311
8.1.12	Expand microgrid off-grid solutions in the new Backup Power for Resilience Program	Microgrids; WMP.462	PU Code Section 8370(d)	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.7, p. 167
8.1.13	Utilize strategic undergrounding to reduce or eliminate the threat of wildfire and the use of PSPS mitigation measures during extreme weather events.	Strategic Undergrounding Program; WMP.473	• GO 95 • GO 128 • SDG&E Underground Construction Standards (UGCS) • SDG&E OHCS Standards	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.2, p. 158

Objective Number	Objectives for Three Years (2023–2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
			• SDG&E Electric Distribution Design Manual • SDG&E Service Standard and Guide • ESP 113.1 – SDG&E Operations & Maintenance Wildland Fire Prevention Plan			
8.1.14	Install automation equipment on 21 circuits within the HFTD areas, with emphasis on Tier 3.	Falling Conductor Protection, Advanced Protection; WMP.463	• SDG&E OHCS 540, 590, 1274 • IEEE 1547-2014, C37.118, 802 • Electronic Industries Alliance (EIA) • International Electrical Commission (IEC) 61850 • Inter-Range Instrumentation Group (IRIG) B Timing Standard • National Electrical Code (NEC) • SDG&E UGCS 3552, 3555, 3560	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.4.3, p. 221
8.1.15	Complete installation of advanced radio frequency sensors (ARFS) and Power Quality (PQ) meters on 30 circuits within the HFTD areas, with emphasis on Tier 2 and Tier 3.	Early Fault Detection; WMP.1195	• SDG&E OHCS 540, 590, 1274 • IEEE 1159 • Electronic Industries Alliance (EIA) • International Electrical Commission (IEC) 61850 • Inter-Range Instrumentation Group (IRIG) B Timing Standard • National Electrical Code (NEC) • SDG&E UGCS 3552, 3555, 3560	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.8.2, p. 172
8.1.16	Complete Tier 3 overhead hardening efforts, continue work on Tier 2 hardening.	Overhead Transmission Hardening, WMP.543	GO 95	Completed work orders/ GIS Data Submission(s)	Tier 3 – 12/31/2023 Tier 2 – 12/31/2027	8.1.2.5.2, p. 164

Objective Number	Objectives for Three Years (2023–2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
		Underground Transmission Hardening, WMP.544 Distribution-underbuild, WMP.545				
8.1.17	Utilize data science methodologies to improve data integrity and develop predictive asset health analyses (Asset 360, IIP)	Asset 360, WMP.1341 IIP, WMP.1342	n/a	Technology roadmaps	12/31/2099 (Ongoing)	8.1.5.4, p. 229
8.1.18	Utilize models to develop, enhance, and expand risk-informed strategies for asset management	Integrated Asset management Systems, WMP.1332	n/a	Technology roadmaps	12/31/2099 (Ongoing)	8.1.5.4 p.229
8.1.19	Continue development of Asset 360 data analytics foundation and integration	Asset 360, WMP.1341	n/a	Asset 360 roadmap	12/31/2099 (Ongoing)	8.1.5.4, p. 229
8.1.20	Utilize LiDAR imagery and Intelligent Image Processing (IIP) for inventory of secondary conductor and services	IIP, WMP.1342	n/a	Inventory of secondary and services	12/31/2025	8.1.5.4, p. 229
8.1.21	Begin integrating digital asset imagery collected from drones, LiDAR, and other assessments into Asset 360	Integrated Asset Management Systems, WMP.1332	n/a	Technology roadmaps	12/31/2099 (Ongoing)	8.1.5.4.2, p. 230
8.1.22	Begin assessing accumulated data and utilizing/adopting geospatial platform	Integrated Asset Management Systems, WMP.1332	n/a	Spatial QDR	12/31/2099 (Ongoing)	8.1.5.4, p. 229
8.1.23	Automate creation of corrective work orders (substation)	Substation Patrol Inspections, WMP.492	n/a	Substation system of record	12/31/2022	8.1.3.11, p. 215
8.1.24	Continue infrastructure inspections per regulatory requirements while exceeding requirements in certain high-risk areas (HFTD and WUI)	Distribution Drone Assessments, WMP.552	• GO 165 • GO 174 • GO 95		12/31/2099 (Ongoing)	8.1.3, p. 187

Objective Number	Objectives for Three Years (2023–2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
		Transmission 69 kV Tier 3 Visual Inspections, WMP.555 Distribution infrared Inspections, WMP.481				
8.1.25	Expand the use and development of enhanced inspection technologies such as Infrared inspections of overhead distribution, drone assessments, and IIP to detect damage and collect data on distribution and vegetation	Distribution Infrared Inspections, WMP.481 Transmission Infrared Inspections, WMP.482 Distribution Drone Assessments, WMP.552	n/a	QDR Table 1; QDR Table 2	12/31/2099 (Ongoing)	8.1.3, p. 187 8.1.5.4.3,p. 232
8.1.26	Perform electric distribution drone inspections on 15% of HFTD and WUI structures prioritized on risk	Distribution Drone Assessments, WMP.552	n/a	QDR Table 1	12/31/2099 (Ongoing)	8.1.3.7, p. 202
8.1.27	Continue the implementation of transmission wood pole intrusive inspections on an 8-year cycle (reduced from 10 years)	Transmission Wood Pole Intrusive inspections, WMP.1190	GO 165	QDR Table 1	12/31/2099 (Ongoing)	8.1.3.6, p. 202
8.1.28	Continue intelligent image processing, utilizing artificial intelligence and innovation to detect damage to high fire risk distribution assets and vegetation	IIP, WMP.1342	n/a	IIP roadmap	12/31/2099 (Ongoing)	8.1.5.4.3,p. 232
8.1.29	Regularly perform internal audits of inspections	QA/QC of Distribution Detailed Inspections, WMP.491 QA/QC of Transmission Inspections, WMP.1191 QA/QC of Distribution Drone Assessments, WMP.1192	n/a	QDR Table 1	12/31/2099 (Ongoing)	8.1.6, p. 233

Objective Number	Objectives for Three Years (2023–2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
		QA/QC of Wood Pole Intrusive Inspections, WMP.1193 QA/QC of Substation Inspections, WMP.1194				
8.1.30	Explore and implement virtual reality/ augmented reality around the proper operation of field and substation equipment	Workforce Planning-Asset Inspections WMP.1334	n/a	TBD	12/31/2025	8.1.9.1, p. 257
8.1.31	Implement dedicated line inspector program to perform routine inspection types	Workforce Planning-Asset Inspections WMP.1334	n/a	Implementation of Line Inspector job classification	12/31/2023	8.1.9.1, p. 257
8.1.32	Examine electric line crew field personnel and first responder training for possible improvements	Workforce Planning-Asset Inspections WMP.1334	n/a	TBD	12/31/2099 (Ongoing)	8.1.9.1, p. 257

OEIS Table 8-2: Grid Design, Operations, and Maintenance Objectives (10-year plan)

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.1.33	Continue to provide fixed backup power solutions to residential and commercial customers who experience frequent PSPS.	Standby Power Programs; WMP.468	Transmission standard practice (confidential)	Third-party data submission	12/31/2099 (Ongoing)	8.1.2.11.2, p. 181
8.1.34	Continue to provide portable backup power solutions to vulnerable, electricity-dependent customers.	Generator Grant Program; WMP.466	Transmission standard practice (confidential)	Third-party data submission	12/31/2099 (Ongoing)	8.1.2.11.3, p. 184

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.1.35	Continue to provide rebates on portable backup power solutions to customers who experience PSPS.	Generator Assistance Program; WMP.467	Transmission standard practice (confidential)	Third-party data submission	12/31/2099 (Ongoing)	8.1.2.11.4, p. 185.
8.1.36	Build 550 Base Stations to deploy a privately-owned LTE network	Distribution Communications Reliability Improvements; WMP.549	IEEE 802	Completed work orders/Primavera P6 Site Schedule.	12/31/2028	8.1.2.8.3, p. 175
8.1.37	Install avian protection equipment on distribution poles in HFTD	Avian Protection; WMP.972	• SDG&E OHCS 1600 • Migratory Bird Treaty Act • Bald and Golden Eagle Protection Act • Codes defined by California Department of Fish and Game	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.10.1, p. 178
8.1.38	Install CAL FIRE-approved lightning arresters in the HFTD	Lightning arrester removal and replacement; WMP.550	• GO 95 • SDG&E OHCS 1247	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.4.6, p. 226
8.1.39	Install switches in strategic locations improving the ability to isolate high-risk areas for potential de-energizations	PSPS Sectionalizing Enhancements; WMP.461	• GO 95 • PU Code Section 451	Completed work orders/ GIS Data Submission(s)	12/31/2032	8.1.2.11.1, p. 181
8.1.40	Expand microgrid off-grid solutions in the new Backup Power for Resilience Program	Microgrids; WMP.462	PU Code Section 8370(d)	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.7, p. 167
8.1.41	Reduce or eliminate the threat of wildfire and the use of PSPS mitigation measures during extreme weather events.	Undergrounding of electric lines and/or equipment; WMP.473	• GO 95 • GO 128 • SDG&E UGCS • SDG&E OHCS • SDG&E Electric Distribution Design Manual	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.2, p. 158

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
			• SDG&E Service Standard and Guide • ESP 113.1 – SDG&E Operations & Maintenance Wildland Fire Prevention Plan			
8.1.42	Complete installation of automated equipment on 82 circuits within the HFTD 2 and 3 areas, with emphasis on completing Tier 3 by 2026.	Falling Conductor Protection; Advanced Protection; WMP.463	• SDG&E OHCS 540, 590, 1274 • IEEE 1547-2014, C37.118, 802 • Electronic Industries Alliance (EIA) • International Electrical Commission (IEC) 61850 • Inter-Range Instrumentation Group (IRIG) B Timing Standard • National Electrical Code (NEC) • SDG&E UGCS 3552, 3555, 3560	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.4.3, p. 221
8.1.43	Install advanced radio frequency sensors (ARFS) and Power Quality (PQ) meters on 100 circuits within the HFTD areas, with emphasis on Tier 2 and Tier 3.	Early Fault Detection; WMP.1195	• SDG&E OHCS 540, 590, 1274 • IEEE 1159 • Electronic Industries Alliance (EIA) • International Electrical Commission (IEC) 61850 • Inter-Range Instrumentation Group (IRIG) B Timing Standard • National Electrical Code (NEC)	Completed work orders/ GIS Data Submission(s)	12/31/2099 (Ongoing)	8.1.2.8, p. 169

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
			• SDG&E UGCS 3552, 3555, 3560			
8.1.44	Complete hardening within the HFTD, begin hardening efforts for high risk WUI areas.	Overhead Transmission Hardening, WMP.543 Underground Transmission Hardening, WMP.544 Distribution-underbuild, WMP.545	GO 95	Completed work orders/ GIS Data Submission(s)	12/31/2026	8.1.2.5.2, p. 164
8.1.45	Enhance data collection of wildfire-related attributes to more granular asset levels with greater frequency	WMP.478, WMP.479, WMP.481, WMP.482, WMP.483, WMP.1190, WMP.552, WMP.488, WMP.489, WMP.555, WMP.492	n/a	TBD	12/31/2099 (Ongoing)	8.1.5.4.1, p. 229 8.1.4.2, p. 220
8.1.46	Evaluate geospatial technology evolution and capability to submit circuit vulnerabilities and automate prioritization to streamline follow-up process.	WMP.478, WMP.479, WMP.481, WMP.482, WMP.483, WMP.1190, WMP.552, WMP.488, WMP.489, WMP.555, WMP.492	n/a	TBD	12/31/2099 (Ongoing)	8.1.5.4.1, p. 229 8.1.4.2, p. 220
8.1.47	Replace legacy transmission asset management system with industry standard technology	WMP.478, WMP.479, WMP.481, WMP.482, WMP.483, WMP.1190, WMP.552, WMP.488, WMP.489, WMP.555, WMP.492	n/a	Transmission system replacement	12/31/2032	8.1.5.2, p. 228
8.1.48	Develop a test case on predictive asset health analyses and risk modeling utilizing integrated asset data to inform asset inspections	WMP.478, WMP.479, WMP.481, WMP.482, WMP.483, WMP.1190, WMP.552, WMP.488, WMP.489, WMP.555, WMP.492	n/a	TBD	12/31/2099 (Ongoing)	8.1.5.4.1, p. 229

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.1.49	Optimize inspection cycles based on risk	WMP.478, WMP.479, WMP.481, WMP.482, WMP.483, WMP.1190, WMP.552, WMP.488, WMP.489, WMP.555, WMP.492	GO 165	Evolution of inspection programs and cycles	12/31/2099 (Ongoing)	8.1.3.1, p. 189
8.1.50	End distribution intrusive inspection 10-year cycle	Distribution Wood Pole Intrusive Inspections, WMP.483	GO 165	TBD	12/31/2032	8.1.3.5, p. 199
8.1.51	Enhance inspection capabilities to identify high risk assets	WMP.478, WMP.479, WMP.481, WMP.482, WMP.483, WMP.1190, WMP.552, WMP.488, WMP.489, WMP.555, WMP.492	n/a	TBD	12/31/2099 (Ongoing)	8.1.3, p. 187
8.1.52	Explore LiDAR use cases in advancing QA/QC processes to inform other asset management strategies	Covered Conductor, WMP.455 Strategic Undergrounding, WMP.473	n/a	TBD	12/31/2099 (Ongoing)	8.1.3.12.1, p. 217
8.1.53	Utilize technology such as Asset360 and the development of asset health indices to perform analysis and determine data-driven, risk-informed maintenance and repair strategies.	Integrated Asset Management Systems, WMP.1332	n/a	Development of risk-informed strategies	12/31/2099 (Ongoing)	8.1.4, p. 218 8.1.5.4.1, p. 229
8.1.54	Develop more robust processes, training, and technologies to monitor and validate work performed	WMP.478, WMP.479, WMP.481, WMP.482, WMP.483, WMP.1190, WMP.552, WMP.488, WMP.489, WMP.555, WMP.492	n/a	TBD	12/31/2099 (Ongoing)	8.1.6, p. 233

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.1.55	Establish a method to track QA/QC results dependent on replacement of legacy system (transmission) and integrate into a system to be developed in the future.	QA/QC of Transmission Inspections, WMP.1191	n/a	TBD	12/31/2032	8.1.6.1, p. 234

8.1.1.2 Targets

OEIS Table 8-3: Grid Design, Operations, and Maintenance Targets by Year

Initiative Activity	Tracking ID	2023 Target & Unit	% Risk Impact 2023	2024 Target & Unit	% Risk Impact 2024	2025 Target & Unit	% Risk Impact 2025	Method of Verification
Wireless Fault Indicators	WMP.449 (8.3.3)	0 WFIs	0%	300 WFIs	0.3395%	0 WFIs	0%	Completed work order/GIS Data Submission(s)
SCADA Capacitors	WMP.453 (8.1.4.3)	15 capacitors	0.0040%	0 capacitors	0%	0 capacitors	0%	Completed work order/GIS Data Submission(s)
Microgrids	WMP.462 (8.1.2.7)	0 microgrids	0%	4 microgrids	98.8932%	0 microgrids	0%	Completed work order/GIS Data Submission(s)
Advanced Protection	WMP.463 (8.1.2.8.1)	5 circuits	0.5755%	8 circuits	0.9207%	8 circuits	0.9207%	Completed work order/GIS Data Submission(s)
Hotline Clamps	WMP.464 (8.1.4.5)	250 HLCs	0.0309%	250 HLCs	0.0309%	100~~950~~ HLCs	0.0129% ~~0.1320%~~	Completed work order/GIS Data Submission(s)
Standby Power Programs	WMP.468 (8.1.2.11.2)	300 generators	33.33%	~~300~~58 generators	8.8146% ~~33.33%~~	89 generators	19.9105%	Third-party data submission

Initiative Activity	Tracking ID	2023 Target & Unit	% Risk Impact 2023	2024 Target & Unit	% Risk Impact 2024	2025 Target & Unit	% Risk Impact 2025	Method of Verification
Strategic Undergrounding	WMP.473 (8.1.2.2)	84 miles	4.7972%	125 miles	7.1387%	28~~125~~ miles	2.1818% ~~7.6234%~~	Completed work order/GIS Data Submission(s)
Traditional Hardening	WMP.475 (8.1.2.5.1)	1.9 miles	0.0037%	0 miles	0%	0 miles	0%	Completed work orders/GIS Data Submission(s)
Distribution Underbuild	WMP.545 (8.1.2.5.2)	7.1 miles	0.0379%	1 mile	0.0053%	1.8 miles	0.0130%	Completed work order/GIS Data Submission(s)
Lightning Arresto~~e~~rs	WMP.550 (8.1.4.6)	1,848 Arresters	0.5099%	1,848 Arresters	0.5099%	90~~1,848~~ Arresto~~e~~rs	0.0248% ~~0.4681%~~	Completed work order/GIS Data Submission(s)
Covered Conductor	WMP.455 (8.1.2.1)	60 miles	0.8142%	60 miles	0.8142%	50~~40~~ miles	0.6790% ~~0.5428%~~	Completed work orders/GIS Data Submission(s)
PSPS Sectionalizing	WMP.461 (8.1.2.11.1)	10 switches	16.6667%	10 switches	16.6667%	10 switches	16.6667%	Completed work orders/GIS Data Submission(s)
Avian Protection	WMP.972 (8.1.2.10.1)	200 poles	0.0204%	200 poles	0.0204%	95~~200~~ poles	0.0102% ~~0.0204%~~	Completed work orders/GIS Data Submission(s)
Expulsion fuse replacement	WMP.459 (8.1.4.4)	40 fuses	0.0849%	0 fuses	0%	80~~700~~ fuses	0.5361% ~~6.0335%~~	Completed work orders/GIS Data Submission(s)
Transmission OH Hardening	WMP.543 (8.1.2.5.2)	14.1 miles	0.3982%	10.2 miles	0.2880%	2~~4.64~~ miles	0.0565% ~~0.1310%~~	Completed work orders/GIS Data Submission(s)
Strategic Pole Replacement Program	WMP.1189 (8.1.2.10.2)	60 poles	0.0538%	267 poles	0.2852%	200~~291~~ poles	0.2167% ~~0.2747%~~	Completed work orders/GIS Data Submission(s)

Initiative Activity	Tracking ID	2023 Target & Unit	% Risk Impact 2023	2024 Target & Unit	% Risk Impact 2024	2025 Target & Unit	% Risk Impact 2025	Method of Verification
Early Fault Detection	WMP.1195 (8.1.2.8.2)	60 nodes	2.6493%	60 nodes	2.6493%	60 nodes	3.5297%	Completed work orders/GIS Data Submission(s)
DCRI	WMP.549 (8.1.2.8.3)	35 stations	n/a	~~60~~5 stations	n/a	5~~42~~ stations	n/a	Completed work orders/Primavera P6 Site Schedule

OEIS Table 8-4: Asset Inspections Targets by Year

Initiative Activity	Tracking ID	Target End of Q2 2023 & Unit	Target End of Q3 2023 & Unit	End of Year Target 2023 & Unit	% Risk Impact 2023	Target End of Q2 2024 & Unit	Target End of Q3 2024 & Unit	End of Year Target 2024 & Unit	x% Risk Impact 2024	Target End of Q2 2025 & Unit	Target End of Q3 2025 & Unit	End of Year Target 2025 & Unit	% Risk Impact 2025	Method of Verification
Distribution Overhead Detailed Inspections	WMP.478 (8.1.3.1)	8,450	9,650	11,100	1.6258%	14,850	15,350	15450	2.2629%	7,294	10,940	13,275	1.9433%	Asset management system
Transmission Overhead Detailed Inspections	WMP.479 (8.1.3.2)	850	1,672	2,387	1.555%	1,121	1,442	1,960	0.9488%	1,239	1,899	2,479	0.9580%	Asset management system
Distribution Infrared Inspections	WMP.481 (8.1.3.3)	6,343	8,147	9,578	1.5678%	150 ~~4,766~~	300 ~~7,149~~	~~9,532~~ 300	0.0491% ~~1.5603%~~	150	300	300	n/a	Asset management system
Transmission Infrared Inspections	WMP.482 (8.1.3.4)	0	0	6,179	0.1848%	0	0	6,179	0.1848%	0	0	7,331	0.1848%	Asset management system
Distribution Wood Pole Intrusive Inspections	WMP.483 (8.1.3.5)	0	50	50	0.0049%	0	0	0	0%	0	344	344	0.03%	Asset management system

Initiative Activity	Tracking ID	Target End of Q2 2023 & Unit	Target End of Q3 2023 & Unit	End of Year Target 2023 & Unit	% Risk Impact 2023	Target End of Q2 2024 & Unit	Target End of Q3 2024 & Unit	End of Year Target 2024 & Unit	x% Risk Impact 2024	Target End of Q2 2025 & Unit	Target End of Q3 2025 & Unit	End of Year Target 2025 & Unit	% Risk Impact 2025	Method of Verification
Transmission Wood Pole Intrusive Inspections	WMP.1190 (8.1.3.6)	0	0	73	n/a	0	0	0	n/a	50	75	114	n/a	Asset management system
Distribution Drone Assessments	WMP.552 (8.1.3.7)	6,848	10,270	13,692	14.1108%	3,250 ~~6,548~~	4,875 ~~9,822~~	~~13,500~~ 6,500	7.7747% ~~13.9129%~~	3,250 ~~4,500~~	4,875 ~~9,000~~	~~13,500~~ 6,500	7.7747% ~~13.9129%~~	Asset management system
Distribution Overhead Patrol Inspections	WMP.488 (8.1.3.8)	61,800	86,500	86,880	4.3853%	71,047	83,247	86,197	4.3508%	70,756	83,236	86,535	4.3679%	Asset management system
Transmission Overhead Patrol Inspections	WMP.489 (8.1.3.9)	6,008	6,008	6,337	0.0298%	6,008	6,008	6,337	0.0298%	3,766	5,650	7,533	0.0298%	Asset management system
Transmission 69kV Tier 3 Visual Inspections	WMP.555 (8.1.3.10)	0	1,632	1,632	0.0193%	0	1,632	1,632	0.0193%	0	1,632	1,632	0.0193%	Asset management system
Substation Patrol Inspections	WMP.492 (8.1.3.11)	192	281	384	n/a	192	281	384	n/a	189	277	384	n/a	Asset management system

8.1.1.3 Performance Metrics

Performance metrics rely on data from a variety of systems. The Ignition Management Program (IMP) (WMP.558) is considered a foundational component of grid design operations and maintenance. This activity alone does not mitigate the risk of wildfire but is critical in understanding the overall wildfire risk in relation to SDG&E equipment assets. See Section 8.1.2.12.2 for details on the IMP.

OEIS Table 8-5: Grid Design, Operations, and Maintenance Performance Metrics Results by Year

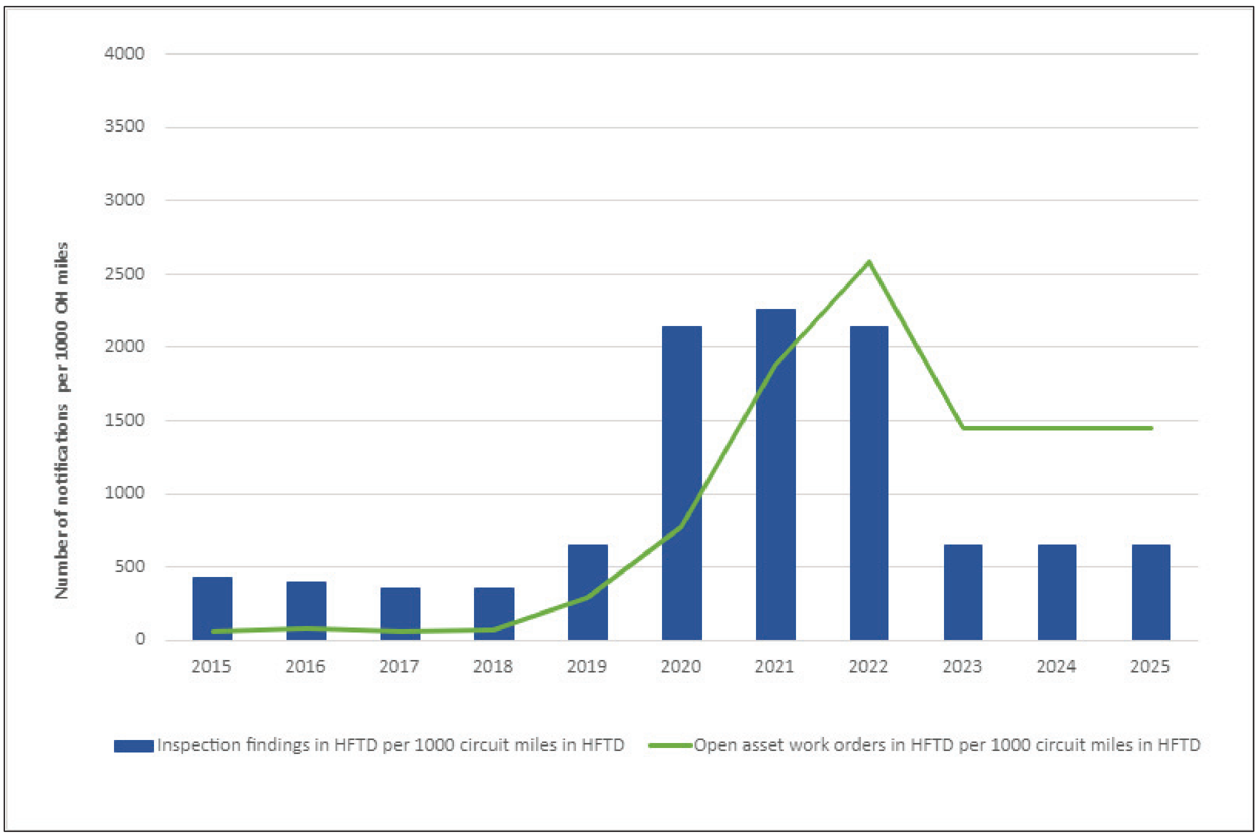
Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification
Distribution Equipment-caused ignitions HFTD	14	6	3	2.73	2.31	2.27	QDR Table 6
Transmission Equipment-caused ignitions HFTD	1	0	0	0.2	0.2	0.2	QDR Table 6
Distribution Equipment-caused outages HFTD	134	164	131	135.42	128.96	120.39	QDR Table 5
Transmission Equipment-caused outages HFTD	5	3	3	3.3	3.13	3.13	QDR Table 5
Distribution inspection findings HFTD	7,565	7,815	7,367	2,250	2,250	2,250	QDR Table 2
Distribution open work orders HFTD	2,734	6,507	8,865	5,000	2,000	2,000	QDR Table 2
Transmission inspection findings HFTD	414	312	515	412	412	412	QDR Table 2
Transmission open work orders HFTD	313	195	165	180	180	180	QDR Table 2

8.1.1.3.1 Distribution Inspection Findings and Open Work Orders

SDG&E's distribution inspection findings have been relatively constant prior to the 2019 WMP, as shown in Figure 8-2. Since then, there has been a clear increase in the number of inspection findings and the number of open work orders within the HFTD. This increase is directly attributable to additional inspections being performed in the HFTD, specifically drone inspections that began in 2019.

The Drone Investigation, Assessment and Repair (DIAR) Program (WMP.552) performed inspections on every HFTD overhead distribution structure between 2019 and 2022. As a result, SDG&E saw an increased rate of DIAR Program findings of about 25 percent compared to approximately 6 percent for ground-based inspections. The above-average influx of open work orders generated from these additional drone inspections is being prioritized and corrected. All 216 emergency items have been repaired and closed and SDG&E continues to work through the lower priority and non-critical items that have been identified. The number of findings from drone inspections is expected to stabilize as the DIAR Program revisits poles that have been previously inspected by drone. The DIAR Program will be inspecting 15 percent of the structures within the HFTD each year, and the finding rate is expected to drop from 25 percent to approximately 15 percent for future inspections.

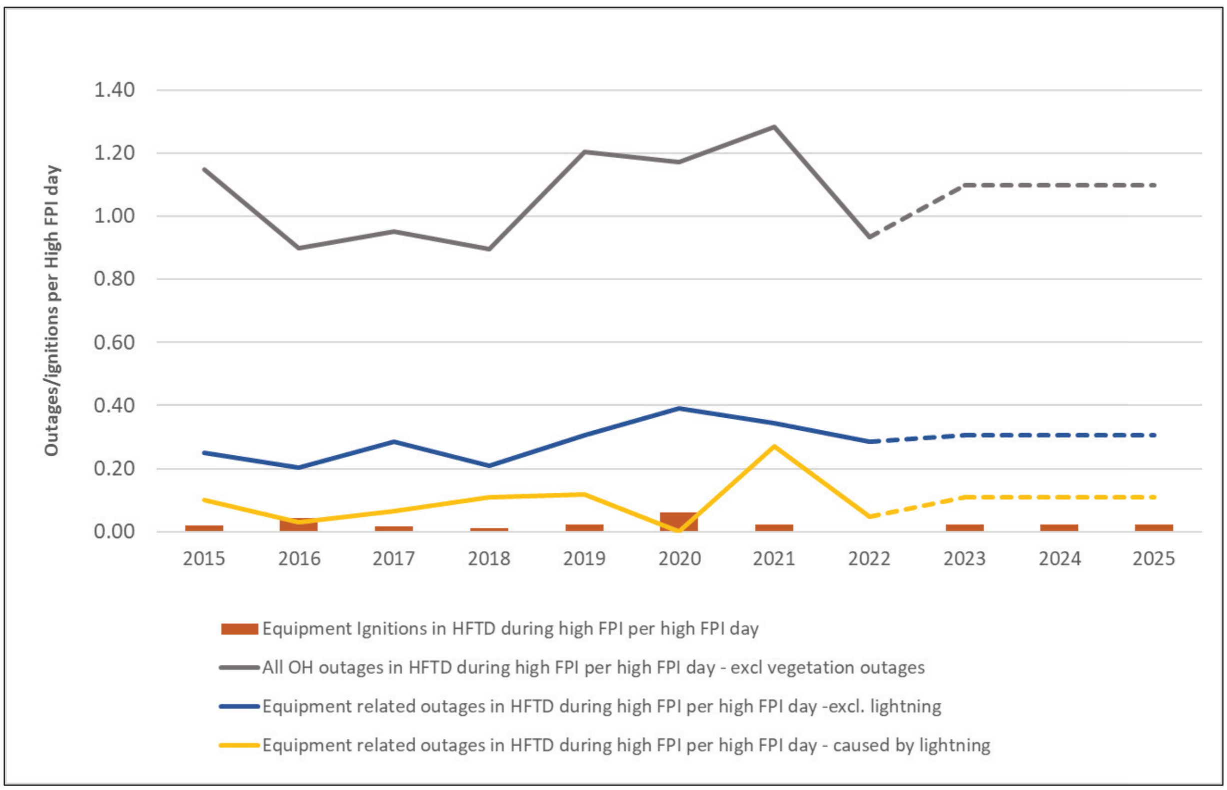
Figure 8-2: Distribution Inspection Findings and Open Work Orders



8.1.1.3.2 Distribution Equipment related HFTD Ignitions and Outages Rate

Outage and ignition data has been normalized to events that occur within the HFTD during days with an FPI rating of elevated or extreme (collectively termed "high FPI day") per the number of high FPI days. This normalization provides a way to review risk events and ignitions that occur during times when wildfire risk is highest, and normalizes them according to the number of days when high wildfire risk days was present. On average, SDG&E has 1.09 overhead outages in the HFTD during high FPI conditions per high FPI day. As shown in Figure 8-3, this rate has been above normal since 2019 although a downward trend was observed in 2022. The spike in 2021 can be explained by the higher-than-normal number of lightning events experienced that year. Despite this increase in lightning events, the number of equipment-related ignitions remained low. Equipment related outages have been relatively flat outside of an increase in 2020 due to a prolonged heat event. The heat event which drove the equipment failures also explains the above average number of equipment-related ignitions in 2020. SDG&E recorded zero equipment-related ignitions in the HFTD during high FPI conditions even though the number of overhead distribution outages was above average. Although this is just one year, SDG&E will continue to monitor this trend as it demonstrates the effectiveness of the grid design, operations, and maintenance initiatives.

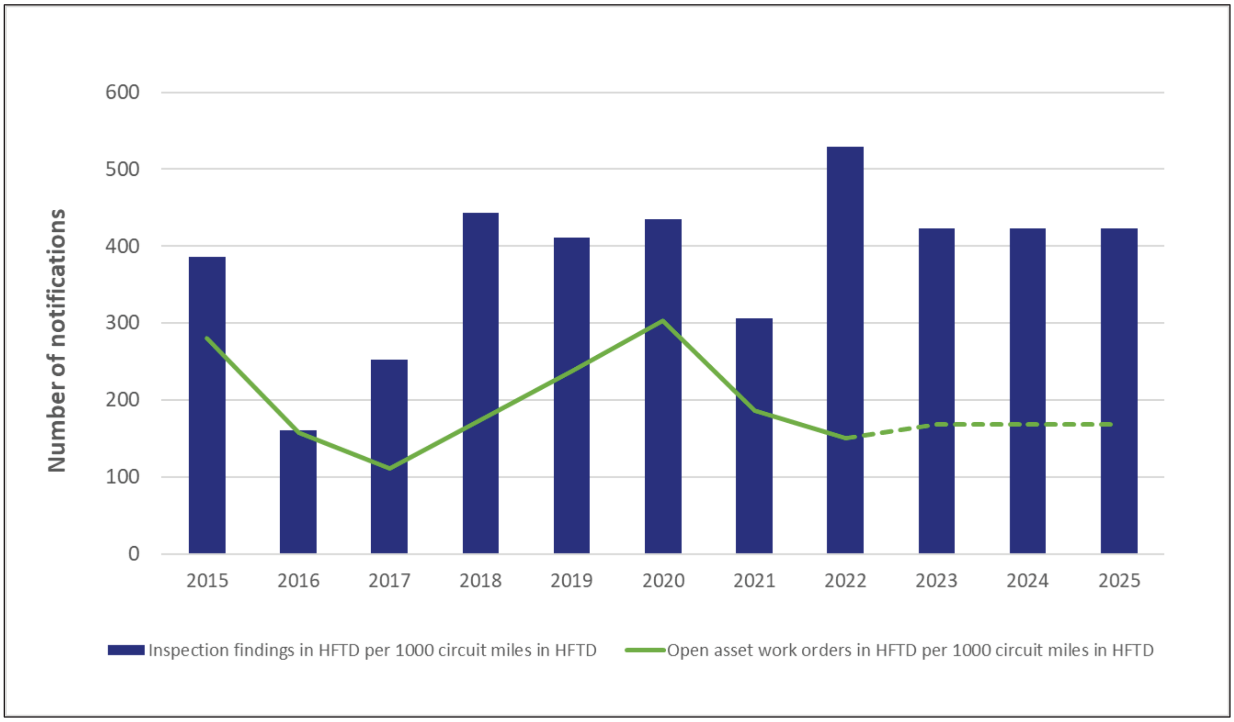
Figure 8-3: Distribution Equipment related HFTD Ignitions and Outages Rate



8.1.1.3.3 Transmission Inspection Findings and Open Work Orders in HFTD

Transmission inspections averaged 365 findings per 1,000 HFTD circuit miles in the HFTD over the past 8 years. As shown in Figure 8-4, the number has some fluctuations, but recently has remained steady demonstrating that the transmission maintenance practice is a mature and effective program. On average, less than 1 percent of the findings identified are Level 1 conditions and approximately 90 percent are Level 2 conditions. The number of open work orders in the HFTD has also remained steady over recent history with a decline in the number of open work orders over the past 3 years. SDG&E forecasts that the number of findings and open work orders will remain at or near current levels for the next 3 years.

Figure 8-4: Transmission Inspection Findings and Open Work Orders in HFTD

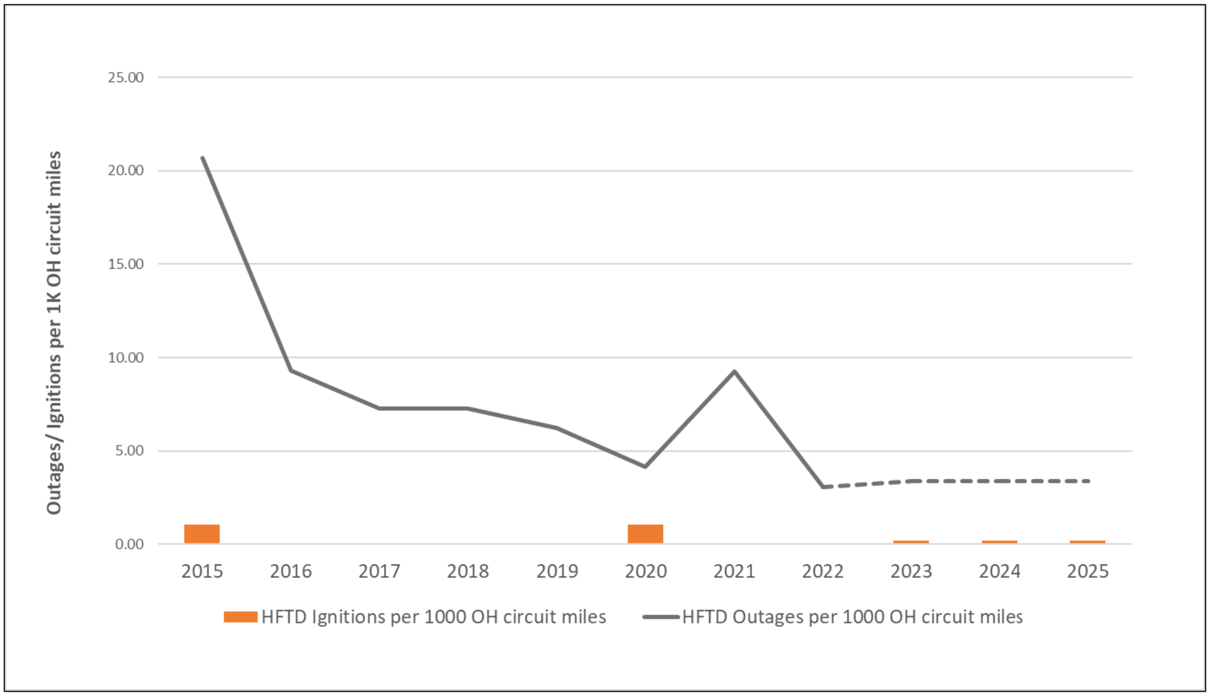


8.1.1.3.4 Transmission Equipment related HFTD Outages and Ignitions

SDG&E's transmission system has been a relatively low source of wildfire risk over the past 8 years. As shown in Figure 8-5, there has been a clear downward trend in the number of equipment-related outages in the HFTD per 1,000 overhead circuit miles. This is in line with SDG&E's studies on the effectiveness of its Transmission Overhead Hardening Program (WMP.543), which has been estimated to be 84 percent.

SDG&E has only recorded two instances of transmission equipment-related ignitions in the HFTD over the past 8 years. Again, this result demonstrates the effectiveness of SDG&E's efforts to harden the transmission system over the past 10 years.

Figure 8-5: Transmission Equipment related HFTD Outages and Ignitions



8.1.2 Grid Design and System Hardening

8.1.2.1 Covered Conductor Installation (WMP.455)

8.1.2.1.1 Utility Initiative Tracking ID

WMP.455

8.1.2.1.2 Overview of the Activity

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of 8 pounds per square foot (psf) or 55 miles per hour (mph) transverse wind load for elevations below 3,000 feet and 6 psf or 48 mph transverse wind load with a half inch of radial ice on conductor for elevations above 3,000 feet. Wind speeds can meet or exceed 85 mph in certain areas of the HFTD. Aging infrastructure, combined with these extreme weather conditions, can increase the possibility of equipment failure on these lines. Further, high winds and outdated design techniques make these lines more vulnerable to foreign object in line contacts, both risk events that could lead to ignitions. To support its initial wildfire resiliency and hardening efforts, SDG&E performed a study to calculate design wind speeds such that SDG&E infrastructure could withstand potential extreme wind events. Infrastructure must be designed to a higher wind speed to allow for a design and safety factor. Based on the study, design wind speeds for infrastructure to withstand the impacts of wind speeds over 85 mph with a max of 111 mph were adopted.

The Covered Conductor Program (WMP.455) is a program that replaces bare conductors with covered conductors in the HFTD. Covered conductors are manufactured with an internal semiconducting layer and external insulating ultraviolet-resistant layers to provide incidental contact protection.

Covered conductor is a widely accepted term to distinguish from bare conductor. The Covered Conductor Program has the potential to raise the threshold for PSPS events to higher wind speeds compared to bare conductor hardening; however, as of the end of 2022 no circuits have been fully hardened with covered conductor and therefore the threshold for PSPS events has not been raised on any circuits with covered conductor installed. RSE calculations developed in the WiNGS-Planning model are utilized to prioritize installation within the HFTD.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

8.1.2.1.3 Impact of the Activity on Wildfire Risk

Over the 3-year period of the 2023 WMP cycle, the Covered Conductor Program (WMP.455) is expected to reduce 0.246 ignitions. This estimate is derived by evaluating different causes of ignitions using 5-year ignition data from 2017 to 2021 and estimating a potential reduction for each cause. The effectiveness of the Covered Conductor Program varies based on each ignition cause (e.g., ignitions caused by animal contact, balloon contact, and vegetation contact have an estimated reduction of approximately 90 percent while ignitions caused by vehicle contact have an estimated reduction of 0 percent). This results in an overall effectiveness estimate of 65 percent. Calculations are shown in SDG&E Table 8-1.

SDG&E Table 8-1: Risk reduction estimation of the Covered Conductor Program

Calculation Component	Component Value
Pre-mitigation risk events per 100 miles Tier 3	8.81
Pre-mitigation risk events per 100 miles Tier 2	8.1
Effectiveness Estimate	65.00%
Post-mitigation risk events per 100 miles Tier 3	8.81 – (65% x 8.81) = 3.08
Post-mitigation risk events per 100 miles Tier 2	8.10 – (65% x 8.10) = 2.835
Ignition rate in Tier 3	2.91%
Ignition rate in Tier 2	2.56%
Pre-mitigation Tier 3 ignitions per 100 miles	8.81 x 2.91% = 0.2564
Pre-mitigation Tier 2 ignitions per 100 miles	8.1 x 2.56% = 0.207
Post-mitigation Tier 3 ignitions per 100 miles	3.08 x 2.91% = 0.089628
Post-mitigation Tier 2 ignitions per 100 miles	2.835*2.56%=0.072576
Ignitions reduced in Tier 3 per 100 miles	0.02564 – 0.089628 = 0.1668
Ignitions reduced in Tier 2 per 100 miles	0.207-0.072756 = 0.134244
Miles of mitigation in Tier 3 (2023-2025)	97
Miles of mitigation in Tier 2 (2023-2025)	63
Ignitions reduced in Tier 3 Post Mitigation	97 x (0.1668/100) = 0.161796
Ignitions reduced in Tier 2 Post Mitigation	63 x (0.134244/100) = 0.084574
Total Ignition Reduction Estimate	0.161796 + 0.084574= 0.24637

8.1.2.1.4 Impact of the Activity on PSPS Risk

The Covered Conductor Program (WMP.455) has the potential to raise the threshold for PSPS events to higher wind speeds compared to bare conductor hardening; however, as of the end of 2022 no circuits have been fully hardened with covered conductor and therefore the threshold for PSPS events has not been raised on any circuits with covered conductor installed. Based on benchmarking with other IOUs and SDG&E's testing of covered conductors, the PSPS wind speed threshold for fully covered circuit segments is expected to be set to between 55 and 60 mph. As discussed in the response to Areas for Continued Improvement SDGE-22-11 in Appendix D, SDG&E expects to complete covered conductor testing and finalize this threshold by December 2023.

8.1.2.1.5 Updates to Initiative

In 2022 SDG&E continued its participation in the covered conductor effectiveness workstream in collaboration with other utilities. The goal of the workstream collaboration is to provide a common effectiveness value for covered conductor and a long-term plan to continually update the data sets that inform this value in respective WMPs. Progress is also expected on comparing the covered conductor mitigation to alternatives, determining the covered conductor mitigation's ability to reduce the need for PSPS (in comparison to alternatives), and developing an initial assessment of the differences in costs. For further discussion regarding the effectiveness of covered conductors, see response to Areas for Continued Improvement Statement SDGE-22-12 in Appendix D. For more information on applying joint lessons learned from the covered conductor effectiveness joint study see response to Areas for Continued Improvement Statement SDGE-22-11 in Appendix D.

As covered conductors become a larger part of the system, performance indicators that impact the efficacy of this mitigation will continue to be monitored and measured, including the measured effectiveness (number of faults per operating year per mile relative to the unhardened system averages) and the cost per mile. SDG&E will also continue to participate in the joint IOU covered conductor workstreams to further develop the estimated and calculated effectiveness of covered conductor.

8.1.2.2 Undergrounding of Electric Lines and/or Equipment (WMP.473)

8.1.2.2.1 Utility Initiative Tracking ID

WMP.473

8.1.2.2.2 Overview of the Activity

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of an 8 psf or 55 mph transverse wind load, however winds can exceed 85 mph in certain areas of the HFTD during extreme Santa Ana conditions. Aging infrastructure also makes the remaining lines more susceptible to equipment failures during high winds and outdated design techniques make these lines more vulnerable to foreign object in line contacts, all of which could lead to ignitions.

The Strategic Undergrounding Program (WMP.473) is a program that converts overhead systems to underground, providing the dual benefits of significantly reducing wildfire risk and the need for PSPS events in these areas. Strategic undergrounding is deployed in the HFTD as well as in areas where substantial PSPS-event reductions can be gained through strategic installation of the underground electric system.

Data on historic PSPS events, wind conditions, and others are reviewed to determine where undergrounding will have the largest impact. Constraints such as environmental, permitting, and design are also taken into consideration. RSE calculations developed in the WiNGS-Planning model are also utilized to prioritize undergrounding within the HFTD.

Strategic undergrounding is the most expensive major hardening alternative on a per mile basis, therefore undergrounding is strategically deployed. For more information on Undergrounding RSE, see response to Areas for Continued Improvement Statement SDGE-22-15 in Appendix D.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

8.1.2.2.3 Impact of the Activity on Wildfire Risk

To calculate the wildfire risk reduction for the Strategic Undergrounding Program (WMP.473), data on historical ignitions associated with underground equipment, pre-mitigation overhead system risk event rate and ignitions rates, and underground mileage to be completed within the current 3-year period of the WMP cycle were analyzed. Specifically, the effectiveness of strategic undergrounding was measured by taking total CPUC-reportable ignitions associated with undergrounding and dividing by total ignitions. Based on this analysis, strategic undergrounding is expected to reduce 0.765 ignitions by the end of 2025.

Calculations are shown in SDG&E Table 8-2.

SDG&E Table 8-2: Risk Reduction Estimation for the Strategic Undergrounding Program

Calculation Component	Component Value
Pre-mitigation risk events per 100 miles Tier 3	8.81
Pre-mitigation risk events per 100 miles Tier 2	8.1
Undergrounding effectiveness	98%
Ignition rate in Tier 3	2.91%
Ignition rate in Tier 2	2.56%
Miles of mitigation in Tier 3 (2023-2025)	180
Miles of mitigation in Tier 2 (2023-2025)	154
Per Mile Baseline	100
Ignitions reduced in Tier 3	(180 ÷ 100) x 8.81 x 2.91% x 98% = 0.452
Ignitions reduced in Tier 2	(154 ÷ 100) x 8.1 x 2.56% x 98% = 0.313
Total Ignition Reduction Estimate	0.452 + 0.313= 0.765

8.1.2.2.4 Impact of the Activity on PSPS Risk

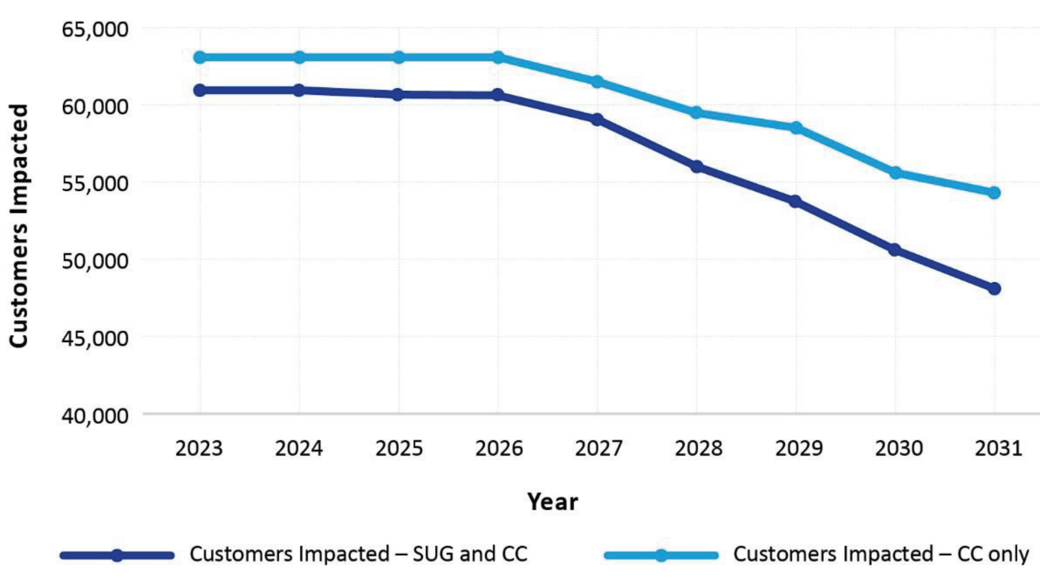
Circuit segments that are fully undergrounded back to the substation source are no longer considered to have a PSPS risk. Undergrounding of electric lines is estimated to reduce PSPS impacts for 3,300 customers from 2023 to 2025.

In 2023, a customer impact study was started to examine how the two most effective grid hardening initiatives, strategic undergrounding and covered conductor, affect PSPS customer impact reduction. To date, three approaches to the study have been attempted with varying results. All three approaches look at the most impactful PSPS de-energization event, which affected 73,000 customers in December 2020, with current conditions to see how accomplishments from these two grid hardening initiatives would reduce PSPS impacts to the same group of customers if the same weather event were to occur annually.

In the most exact approach to the study, weather stations connected to de-energized segments from the December 2020 PSPS de-energization were matched to the segment structure in 2023. These matched segments and their associated 73,000 customers serve as the study population. The actual and planned hardening of these segments, which includes both undergrounding and covered conductor, was then compared to a hypothetical covered conductor only hardening in terms of annual customer impact.

Preliminary results in Figure 8-6 show that if the 2020 PSPS event hypothetically occurred annually, undergrounding of electric lines combined with covered conductor installation on these segments would reduce annual PSPS impacts for more customers than covered conductor installation alone. By 2031, PSPS impacts would be reduced for approximately 34% or 24,643 of the 73,000 affected customers when considering both strategic undergrounding of electric lines and covered conductor installation mitigations. Alternatively, if only covered conductor mitigations are considered, preliminary results show that by 2031, PSPS impacts would be reduced for approximately 26% or 18,908 of the 73,000 affected customers.

Figure 8-6: Projected PSPS Impact Reduction



8.1.2.2.5 Updates to the Activity

Enhancements in 2023 will include:

- Implement various types of equipment such as trenchers and rock saws to reduce the cost of civil construction, especially in rocky terrains.

- Benchmark with neighboring utilities on different construction methods and design guidelines to improve existing design deliverables.
- Continue to look for ways to reduce trench dimensions where possible to reduce costs and schedule impacts.
- Partner with neighboring utilities strategically to tackle permit delays with Caltrans.
- Partner with communication entities such as Cox and Caltrans middle mile projects on the broadband initiatives where opportunities exist to joint trench.
- Create permitting strike team to manage and expedite WMP-related permitting and agency approvals.
- Re-evaluate Strategic Undergrounding Program (WMP.473) contracting strategy to address resource constraints and workload increase. On board a contracted alliance partner to help support the expansion of the overall program and create a robust PMO to support significantly scaling up the program to meet the increase volume of work.

Over the next 10 years, the scope of the Strategic Undergrounding Program is expected to increase as the understanding of costs and constraints improve. Installations in the HFTD remain challenging due to difficult terrain, environmental constraints, permitting timelines, and acquisition of easements and land rights. Facilitating productive engagement with stakeholders in the telecommunication field will help streamline resources and obtain more support for undergrounding efforts. Lessons learned from each year's undergrounding accomplishments will help alleviate constraints through process improvements and stakeholder engagement.

For further discussion regarding the Strategic Undergrounding Program, see response to Areas for Continued Improvement SDGE-22-15 in Appendix D.

8.1.2.3 Distribution Pole Replacements and Reinforcements (WMP.458)

8.1.2.3.1 Utility Initiative Tracking ID

WMP.458

8.1.2.3.2 Overview of the Activity

The Distribution Pole Replacement and Reinforcement Program (WMP.458) is a program that replaces deteriorated wood distribution poles and other asset-related components identified through inspection programs (e.g., Corrective Maintenance Program (CMP) and wood pole intrusive inspections WMP.1190 and WMP.483) to reduce the risk of ignitions. See Section 8.1.3 Asset Inspections Asset Inspections and 8.1.7 Open Work Orders for more information on inspection programs and corrective work.

Replaced poles are constructed to site-specific design criteria (e.g., wood poles will be replaced with steel poles that meet the known local wind conditions of a particular area). Power Line Systems – Computer Aided Drafting and Design (PLS-CADD) modeling is used to design pole replacement work in the HFTD. In addition, pole loading calculations are reviewed by a designated engineering team.

For poles identified in Tier 3 of the HFTD, replacement is accelerated faster than the 6-month timeframe required by GO 95. In addition to pole replacement, any other identified issues are remediated to clear potential infractions and vulnerabilities in the system. All distribution pole replacements are audited by Civil/Structural Engineering. This audit can consist of desktop and/or field audits. Any issues found are routed back to the district or contractor who performed the work for resolution.

8.1.2.3.3 Impact of the Activity on Wildfire Risk

By replacing deteriorated wood distribution poles, this program reduces the likelihood of equipment failures which could lead to an ignition. This initiative does not have its own Risk Reduction Estimation Methodology because its risk reduction is included with asset inspection programs. Risk Reduction Estimation Methodology for asset inspection programs is provided in Section 8.1.3 Asset Inspections.

8.1.2.3.4 Impact of the Activity on PSPS Risk

The Distribution Pole Replacement and Reinforcement Program (WMP.458) focuses on reducing wildfire risk. It has no impact on the risk of PSPS.

8.1.2.3.5 Updates to the Activity

The Distribution Pole Replacement and Reinforcement Program (WMP.458) does not have specific targets set as all replacement work is reactive and based on findings from asset inspection programs. Proactive pole replacements are performed with other grid hardening initiatives. No changes were made to this Program in 2022 and none are expected to be made in 2023.

8.1.2.4 Transmission Pole/Tower Replacements and Reinforcements (WMP.472)

8.1.2.4.1 Utility Initiative Tracking ID

WMP.472

8.1.2.4.2 Overview of the Activity

The Transmission Pole/Tower Replacement and Reinforcement Program (WMP.472) is a program that replaces deteriorated wood transmission poles and other asset-related components identified through inspection programs (e.g., CMP and wood pole intrusive inspections WMP.1190 and WMP.483) to reduce the risk of ignitions. See Section 8.1.3 Asset Inspections Asset Inspections and 8.1.7 Open Work Orders for more information on inspection programs and corrective work.

Replaced poles are constructed to site-specific design criteria (e.g., wood poles will be replaced with steel poles that meet the known local wind conditions of a particular area). PLS-CADD modeling is used to design pole replacement work in the HFTD. In addition, pole loading calculations are reviewed by a designated engineering team.

Poles identified for replacement in Tier 3 of the HFTD are accelerated to a 6-month timeframe required by GO 95. In addition to pole replacement, other issues are identified and prioritized to remediate potential infractions and vulnerabilities in the system.

8.1.2.4.3 Impact of the Activity on Wildfire Risk

By replacing deteriorated transmission poles, this program reduces the likelihood of equipment failures which could lead to an ignition. This initiative does not have its own Risk Reduction Estimation Methodology because its risk reduction is included with asset inspection programs. Risk Reduction Estimation Methodology for those programs is provided in Section 8.1.3 Asset Inspections.

8.1.2.4.4 Impact of the Activity on PSPS Risk

The Transmission Pole/Tower Replacement and Reinforcement Program focuses on reducing wildfire risk. It has no impact on the risk of PSPS.

8.1.2.4.5 Updates to the Activity

The Transmission Pole/Tower Replacement and Reinforcement Program does not have specific targets set as all replacement work is reactive and based on findings from the various asset inspection programs. Proactive pole/tower replacements are performed with other grid hardening initiatives. No changes were made to this Program in 2022 and none are expected to be made in 2023.

8.1.2.5 Traditional Overhead Hardening

8.1.2.5.1 Distribution Overhead System Hardening (Traditional) (WMP.475)

Utility Initiative Tracking ID

WMP.475

Overview of the Activity

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of an 8 psf or 55 mph transverse wind load, however winds can exceed 85 mph in certain areas of the HFTD during extreme Santa Ana conditions. Aging infrastructure makes lines more susceptible to equipment failures and outdated design techniques make these lines more vulnerable to foreign object in line contacts during high winds, all of which could lead to ignitions.

The ESH Program (WMP.459, WMP.453, WMP.550, WMP.464) (previously the FiRM, PRiME, and WiSE programs) is a program whose scope includes the replacement of wood poles with steel, the replacement of conductors with uncovered or covered conductors, and in some cases the permanent removal of overhead facilities. It targets fire prone areas including the HFTD and WUI.

The consolidation of overhead hardening programs into the ESH Program resulted in the execution of projects based on a circuit-by-circuit approach that weighs risk inputs alongside the need to reduce PSPS impacts, rather than scoping projects based on specific wire or at-risk poles. Combining overhead distribution hardening programs makes project engineering, design, construction, and management more efficient and minimizes impacts to customers during job walks, construction, and post construction close-out activities.

In 2021, the WiNGS-Planning model was introduced. Traditional Hardening work that was started prior to this model is expected to be completed by 2024 and any new work that is scoped will be developed utilizing the WiNGS-Planning model. Completion of approximately 1.9 miles is expected in 2023 and approximately 0.6 miles is expected in 2024. Currently, the ESH Program is not expected to continue in 2025 or beyond.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

Impact of the Activity on Wildfire Risk

To determine the estimated ignition reduction for overhead system hardening, data on average historical pre-mitigation risk events, mitigation effectiveness, historical ignition rates, and the amount of overhead hardening planned to be completed in the 2023 to 2025 timeframe of the WMP cycle was analyzed. Based on this analysis, the ESH Program is estimated to reduce ignitions by 0.00048 by the end of 2025. Calculations are shown in SDG&E Table 8-3.

SDG&E Table 8-3: Risk Reduction Estimation for Distribution Overhead Hardening

Calculation Component	Component Value
Pre-mitigation risk events per 100 miles Tier 3	8.8
Pre-mitigation risk events per 100 miles Tier 2	8.1
Post-mitigation risk events per 100 miles Tier 3	6.9
Post-mitigation risk events per 100 miles Tier 2	3.3
Ignition rate in Tier 3	2.91%
Ignition rate in Tier 2	2.56%
Risk events reduced Tier 3	8.8 – 6.9 = 1.9
Risk events reduced Tier 2	8.1 – 3.3 = 4.8
Miles of mitigation in Tier 3	1.5
Miles of mitigation in Tier 2	0.4
Per Mile Baseline	100
Effectiveness estimate Tier 3	22%
Effectiveness estimate Tier 2	60%
Ignitions reduced in Tier 3	(1.5 ÷ 100) x 1.9 x 2.91% x 22% = 0.000182
Ignitions reduced in Tier 2	(0.4 ÷ 100) x 4.8 x 2.56% x 60% = 0.000295
Total Ignition Reduction Estimate	0.000182 + 0.000295 = 0.000477

Impact of the Activity on PSPS Risk

The ESH Program focuses on reducing the risk of wildfire. It has no impact on the risk of PSPS.

Updates to the Activity

Enhancements in 2023 will include fully transitioning the ESH Program prioritization process to the WiNGS-Planning model. Legacy traditional hardening projects will continue to be closed out in the future.

8.1.2.5.2 Transmission System Hardening Program (WMP.543, WMP.544, WMP.545)

Utility Initiative Tracking ID

WMP.543, WMP.544, WMP.545

Overview of the Activity

SDG&E operates and maintains approximately 1,993 miles of transmission infrastructure, including 993 miles of overhead transmission infrastructure in the HFTD. Aging infrastructure makes lines more susceptible to equipment failures and outdated design techniques make these lines more vulnerable to foreign object in line contacts during high winds, all of which could lead to ignitions.

The Transmission System Hardening Program is comprised of three parts: Overhead Transmission Hardening (WMP.543), Underground Transmission Hardening (WMP.544), and Distribution Underbuild (WMP.545). Overhead Transmission hardening utilizes enhanced design criteria to replace wood poles with steel poles, replace aging conductors with high-strength conductors, and increase conductor spacing in the HFTD to reduce the chance of risk events and ignitions. Underground Transmission Hardening replaces the overhead structures altogether and nearly eliminates the risk of wildfire from those tie line segments. The Distribution Underbuild Program replaces the overhead distribution equipment that is attached to the same poles and along the same route as the work that is completed in the overhead transmission hardening jobs. By including distribution underbuild work with overhead transmission work, costs are reduced due to the ability to combine charges such as design and labor.

The Transmission System Hardening Program prioritizes hardening activity in the HFTD, starting with Tier 3 and moving into Tier 2.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

Impact of the Activity on Wildfire Risk

Hardening overhead transmission lines in the HFTD reduces ignition risk due to foreign object line contacts, wire slaps, and equipment failure during high wind conditions. By replacing wood poles with steel poles, replacing aging conductors with high strength conductors, and designing to known local wind conditions, the risk of equipment failure is reduced during adverse weather conditions. Correspondingly, increasing conductor spacing reduces the risk of vegetation contact and wire slaps during adverse weather conditions.

To determine the estimated ignition reduction for the Transmission System Hardening Program, data on average historical transmission risk events, average historical transmission ignition rates, the measured effectiveness of hardened transmission lines, and the amount of hardening expected to be completed in the 2023 to 2025 WMP cycle was analyzed. For the distribution underbuilt components, historical information used for distribution hardening was applied to the miles of distribution underbuilt on transmission. Utilizing this methodology, a reduction of 0.125 transmission ignitions and 0.0084 distribution ignitions for the associated underbuilt was estimated. Calculations are shown in SDG&E Table 8-4 and SDG&E Table 8-5 respectively.

SDG&E Table 8-4: Risk Reduction Estimation for Transmission Overhead Hardening

Calculation Component	Component Value
Pre-mitigation risk events per 100 miles Tier 3	33.069
Pre-mitigation risk events per 100 miles Tier 2	4.222
Effectiveness Estimate Tier 3	85%
Effectiveness Estimate Tier 2	96%
Post-mitigation risk events per 100 miles Tier 3	33.069 x (1-85%) = 4.96
Post-mitigation risk events per 100 miles Tier 2	4.22 x (1-96%) = 0.1688
Transmission Ignition Rate Tier 3	13.64%
Transmission Ignition Rate Tier 2	11.11%

Calculation Component	Component Value
Risk Event Reduced Tier 3	33.069 – 4.96 = 28.126
Risk Event Reduced Tier 2	4.22 – 0.1699 = 4.051
Miles of mitigation Tier 3	0
Miles of mitigation Tier 2	28.94
Per Mile Baseline	100
Ignitions reduced Tier 3	28.126 x (0 ÷ 100) x 13.64% x 85% = 0.0
Ignitions reduced Tier 2	4.051 x (28.94 ÷ 100) x 11.11% x 96% = 0.125039
Total Ignitions reduced Overhead	0 + 0.125039 = 0.125039

SDG&E Table 8-5: Risk Reduction Estimation for Transmission-Distribution Underbuilt

Calculation Component	Component Value Tier 3	Component Value Tier 2
Numbers of Faults Prior Mitigation	4.43	4.8
Numbers of Faults After Mitigation	2.46	2.66
Numbers of Average HFTD Faults	213	227
Numbers of Total HFTD Faults	132.9	145.4
Average HFTD Faults Prior Mitigation	4.43 x 213 ÷ 132.9 = 7.10	4.8 x 227 ÷ 145.4 = 7.49
Average HFTD Faults After Mitigation	2.46 x 213 ÷ 132.9 = 3.94	2.66 x 227 ÷ 145.4 = 4.16
Historical Ignition Rate	2.91%	2.56%
Numbers of Ignitions before Migration	7.10 x 2.91% = 0.21	7.49 x 2.56% = 0.19
Numbers of Ignitions after Migration	3.94 x 2.91% = 0.11	4.16 x 2.56% = 0.11
Total Ignition Reduction by Hardening	0.21 – 0.11 = 0.092	0.19 – 0. 11 = 0.085
Installation/Repairment/Replacement	0	9.9
Per Mile Baseline	100	100
Effectiveness Estimate	100%	100%
Total Ignition Reduced	(0 ÷ 100) x 0.092 x 100% = 0	(9.9 ÷100) x 0.085 x 100% = 0.008415

Impact of the Activity on PSPS Risk

The Transmission Overhead System Hardening Program focuses on reducing the risk of wildfire. It does not have a PSPS risk reduction value associated with it.

Updates to the Activity

SDG&E plans to complete approximately 50 miles of transmission overhead system hardening, including distribution underbuild, by the end of the 2023-2025 WMP cycle.

8.1.2.6 Emerging Grid Hardening Technology Installations and Pilots

SDG&E is not currently piloting additional grid hardening technologies. However, grid hardening initiatives such as Advanced Protection Program (APP) (WMP.463) and Early Fault Detection (EFD) (WMP.1195) utilize emerging and advanced technologies to enable system automation and failure detection.

As described in Section 8.1.2.8.1, APP employs various technologies aimed to prevent and mitigate the risks of fire incidents, provide better transmission and distribution sectionalization, and create higher visibility and situational awareness in fire-prone areas.

EFD employs technologies such as ARFS and Power Quality (PQ) Meters (WMP.1195) to detect and prevent significant equipment failures before they occur. See Section 8.1.2.8.2 for more information on EFD.

The Distribution Communications Reliability Improvement (DCRI) Program (WMP.549) enables APP and EFD technologies as a reliable communication network is necessary for initiatives that require continuous communication. See Section 8.1.2.8.3 for more information on DCRI.

8.1.2.7 Microgrids (WMP.462)

8.1.2.7.1 Utility Initiative Tracking ID

WMP.462

8.1.2.7.2 Overview of the Activity

The Microgrid Program (WMP.462) is a program that designs and builds microgrids that can be electrically isolated during a PSPS event, thereby maintaining electric service to customers who would otherwise be affected. While alternative hardening solutions, such as strategic undergrounding, may be better at simultaneously mitigating wildfire risk, those options are not always technically feasible or cost-effective. For instance, customers who are located far away from a substation or central source of generation would require additional mileage of undergrounding that can be cost-prohibitive. Additionally, undergrounding may not be feasible, whether due to hard rock, environmental, or cultural concerns.

A combination of data including the risk of wildfire from overhead infrastructure, feasibility of traditional overhead hardening solutions, alternative solutions such as undergrounding distribution infrastructure, and historical PSPS impact data is used to guide the installation of microgrids. Additional information such as identification of critical facilities or AFN customers is incorporated into prioritizing targeted locations for a potential microgrid project. The majority of microgrid installations are in the HFTD.

8.1.2.7.3 Impact of the Activity on Wildfire Risk

The focus of the Microgrid Program (WMP.462) is to mitigate the consequences of PSPS events on customers that would otherwise be affected by de-energization.

8.1.2.7.4 Impact of the Activity on PSPS Risk

Over the 3-year period of the 2023 WMP cycle, microgrids are expected to reduce PSPS impacts to a total of 356 customers. This number is calculated based on the locations of microgrids and the customers they serve and is used to estimate the reduction in PSPS impact to calculate the RSE. Because microgrids are designed to keep customers energized throughout the duration of a PSPS event, the effectiveness of the mitigation is estimated to be 100 percent. This number does not include nearby customers who are not energized by the microgrid (and could experience a PSPS event), but nevertheless benefit from critical locations being energized by the microgrid.

8.1.2.7.5 Updates to the Activity

Currently, 4 microgrids are planned to be completed by 2024. Locations currently under review include Cameron Corners, Butterfield Ranch, Shelter Valley, and potentially an off-grid solution (the name is still being determined). The Cameron Corners microgrid is located on Circuit 448, while the remaining three are located on Circuit 221.

The Cameron Corners microgrid, located in Tier 3 of the HFTD, is a remote, low-income community in the eastern part of San Diego County. The microgrid has been supporting 13 customers in its temporary configuration (e.g., conventional generators) since 2020. Customers range from residential, commercial, essential, and MBL. The permanent renewable solutions [875 kilowatts (kW) solar and 2.4 megawatt-hours (MWh) energy storage resource] are planned to be completed in 2024. In addition to the customers already identified, the microgrid will provide significant benefits to the surrounding rural community during de-energization events.

The Butterfield Ranch microgrid is a desert community in the eastern part of the service territory. Although the microgrid itself is not located in the HFTD, the circuit that feeds Butterfield Ranch is within Tier 2 and Tier 3 of the HFTD. The microgrid has been supporting 119 customers in its temporary configuration (e.g., conventional generators) since 2020. Customers range from residential, commercial, essential, and medical baseline. The permanent renewable solutions (2.1 megawatts (MW) solar and 4 MWh energy storage resource) are planned to be completed in 2025.

The Shelter Valley microgrid is a desert community in the far eastern section of the service territory. Although the microgrid itself is not located in the HFTD, the circuit that feeds Shelter Valley is within Tier 2 and Tier 3 of the HFTD. The microgrid has been supporting 223 customers in its temporary configuration (e.g., conventional generators) since 2020. Customers range from residential, commercial, essential, and MBL. The permanent renewable solutions (2.4 MW solar and 4.8 MWh energy storage resource) are planned to be completed in 2025.

Off-grid technologies (also referred to as Remote Grid) are being evaluated as an additional solution to mitigate costly hardening efforts for long lines with minimal customer loading.

Additionally, mobile battery solutions are, and will continue to be, deployed to create temporary microgrid solutions in order to support communities as well as Community Resource Centers (CRCs) and minimize traditional generator run-time during extended PSPS events.

The WiNGS-Planning model is utilized to explore the potential use of segment-level risk analysis to inform the identification of additional microgrid sites as a potential alternative to other initiatives such as grid hardening.

8.1.2.8 Installation of System Automation Equipment

8.1.2.8.1 Advanced Protection (WMP.463)

Utility Initiative Tracking ID

WMP.463

Overview of the Activity

SDG&E operates and maintains nearly 3,500 miles of overhead distribution circuit miles within the HFTD. This infrastructure was originally designed to meet GO 95 requirements of an 8 psf or 55 mph transverse wind load, however winds can exceed 85 mph in certain areas of the HFTD during extreme Santa Ana conditions. Aging infrastructure also makes the remaining lines more susceptible to equipment failures and outdated design techniques, making these lines more vulnerable to foreign object in line contacts during high winds, all of which could lead to ignitions.

The APP (WMP.463) develops and implements advanced protection technologies within electric substations and on the electric distribution system. It aims to prevent and mitigate the risks of fire incidents, provide better transmission and distribution sectionalization, create higher visibility and situational awareness in fire-prone areas, and allow for the implementation of new relay and automation standards in locations where protection coordination is difficult due to lower fault currents attributed to high impedance faults.

More advanced technologies, such as microprocessor-based relays with synchrophasor/phasor measurement unit (PMU) capabilities, real-time automation controllers, auto-sectionalizing equipment, line monitors, direct fiber lines, Private LTE and wireless communication radios comprise the portfolio of devices that are installed in substations and on distribution circuits to allow for a more comprehensive protection system and greater situational awareness in the fire-prone areas of the HFTD. Advanced protection technologies implemented by this program include:

- Falling Conductor Protection (FCP) designed to trip distribution and transmission overhead circuits before broken conductors can reach the ground energized
- Sensitive Ground Fault (SGF) Protection for detecting high impedance faults resulting from downed overhead conductors that result in very low fault currents
- Sensitive Relay Profile (SRP) Settings enabled remotely on distribution equipment to reduce fault energy and fire risk
- High Accuracy Fault Location for improved response time to any incident on the system
- Remote Relay Event Retrieval and Reporting for real-time and post-event analysis of system disturbances or outages
- SCADA Communication to all field devices being installed for added situational awareness
- Increased Sensitivity and Speed of Transmission Protection Systems to reduce fault energies and provide swifter isolation of transmission system faults
- Protection Integration with emerging telecommunications technologies such as direct fiber, Private LTE and wireless radios as a means of facilitating the communication infrastructure needs of APP

APP replaces aging substation infrastructure such as obsolete 138 kilovolt (kV), 69 kV, and 12 kV substation circuit breakers, electro-mechanical relays, aging solid-state relays, aging microprocessor relays and Remote Terminal Units (RTUs). New circuit breakers incorporating microprocessor-based relays, RTUs, and the latest in communication equipment are also installed in substations within the HFTD. On distribution circuits within the HFTD, APP coordinates with the overhead system hardening programs to strategically install or replace sectionalizing devices, line monitors, direct fiber lines, and communication radios to facilitate the requirements of SDG&E's advanced protection systems.

Impact of the Activity on Wildfire Risk

By replacing aging infrastructure, installing distribution sectionalizing devices, increasing the sensitivity and speed of protection systems, and utilizing high accuracy, high speed communication networks, APP (WMP.463) reduces fault energies and provides swifter isolation of system faults, resulting in lower wildfire risk.

The ignitions reduced by 2025 was calculated using the 5-year average risk events caused by wire downs, the 5-year average ignitions, the assumed effectiveness of 100 percent, and the number of planned APP installations for the WMP timeframe. The mitigation will have an estimated 100 percent reduction in ignitions based on the technology and what the product is designed to accomplish. Based on this data, a reduction of 0.203 and 0.056 ignitions in Tier 3 and Tier 2, respectively, are expected by the end of 2025. Calculations are shown in SDG&E Table 8-6.

SDG&E Table 8-6: Risk Reduction Estimation for Advance Protection

Calculation Component	Component Value
Tier 3 wire downs (2017-2021 average)	15.8
Tier 2 wire downs (2017-2021 average)	21.6
Wire down with connection failures Tier 3	2.75
Wire down with connection failures Tier2	3
Wire Down Mitigated Tier 3	15.8–- 3.75 = 13.050
Wire Down Mitigated Tier 2	21.6–- 3 = 18.6
Ignition rate Tier 3 (2017 – 2021 average)	2.91%
Ignition rate Tier 2 (2017 – 2021 average)	2.56%
No of Pre-mitigation ignitions Tier 3	13.050 x 2.91% = 0.3795
No of Pre-mitigation ignitions Tier 2	18.6 x 2.56% = 0.4762
Mitigation Effectiveness Estimate	100%
Ignitions reduction estimate Tier 3	0.3795 x 100% = 0.3795
Ignitions reduction estimate Tier 2	0.4762 x 100% = 0.4762
Installed in Tier 3	15
Installed in Tier 2	6
Total Tier 3 circuits	28
Total Tier 2 circuits	54
Ignitions reduced Tier 3	0.3795 x (15 ÷ 28) = 0.203304

Calculation Component	Component Value
Ignitions reduced Tier 2	0.4762 x (6 ÷ 54) = 0.056
Total Ignitions reduced	0.203304 + 0.056 = 0.259304

Impact of the Activity on PSPS Risk

Upgrades associated with APP (WMP.463) and increased sectionalization can also lead to reduced PSPS impacts. The reduction in PSPS impacts is directly related to the greater number of sectionalizing devices installed on the system as a part of this program. This reduces customer counts between sectionalizing devices, which can reduce the number of customers de-energized during weather events.

Updates to the Activity

Coordination with adjacent programs such as the Strategic Undergrounding Program (WMP.473) and the Covered Conductor Program (WMP.455) has continued in order to further refine efficient deployment of FCP on distribution circuits in the HFTD. Teams meet on a recurring basis to review target circuits for FCP, strategic undergrounding and installation of covered conductor scope to ensure FCP is not deployed on segments of circuits planned to be undergrounded. FCP still provides effective protection of circuits converted to covered conductor, and when possible, both are deployed simultaneously. Between 2023 and 2025, SDG&E plans to complete installation of FCP on 21 circuits within the HFTD areas, with emphasis on Tier 3.

The following next steps have been identified as countermeasures to the risks encountered in 2022:

- SDG&E’s Land team is currently working with tribal land representatives to establish new process and timelines on achieving new easements.
- Processes have been adjusted to proactively research locations in the Bureau of Indian Affairs (BIA) and other potentially challenging jurisdictions to identify locations which may require extended permitting durations. When this occurs, the permitting task duration and downstream in-service dates are adjusted to reflect realistic completion dates.
- The number of circuit designs initiated will be increased to be at least 150 percent over our initiative targets to reduce the risk of missing our forecasted goal.

SDG&E successfully detected a broken conductor which occurred on a recently enabled FCP circuit in October of 2022. On October 29, 2022, SDG&E responded to reports of a wire down on 12 kV Circuit C217 out of Rincon Substation. Upon arrival, it was confirmed there was a wire down and repairs were needed to restore the circuit to normal configuration.

Upon investigation of FCP event records, it was discovered that the SDG&E FCP scheme on C217 successfully detected the broken conductor. The scheme was still in test mode at the time and did not act to trip the circuit segment, as SDG&E has not yet enabled full tripping mode. However, this event which shows the system not only works in lab and field-testing environments, but also in real world scenarios. SDG&E is continuing its strategic deployment of FCP throughout the HFTD and will continue to validate real-world scenarios which improve the efficacy of the technology.

In addition, Wire Down Detection (WDD) and EFD demonstration projects were completed in 2022.

Early Fault Detection (EFD) (WMP.1195)

The EFD demonstration project was successfully completed in 2022 with positive results. An EFD Program is currently being created as detailed in Section 8.1.2.8.2.

Wire Down Detection (WDD)

WDD is an innovative concept which leverages existing advanced metering infrastructure (AMI) network, providing "near time" analysis of circuit events. The goal of this project was to use AMI data to detect wire down in distribution networks. Preliminary analysis of WDD data showed promising results. The advanced analytics developed as part of this project have demonstrated energized downed conductors and single-phase faults can be identified in near real time. When the analytic programs detect a wire down with high confidence, an alert is emailed to the distribution list and also shows as an icon on a GIS map.

During the demonstration phase, WDD test data was validated via field inspection and root cause was compared to how the WDD system responded in the test environment. Test results demonstrated that if the AMI Workforce Management (WFM) application was operational in a production environment, the time savings provided by the application may have yielded significant wildfire risk reduction. In addition, the AMI WFM application can identify single-phase fault incidents. Currently, the only way to discover single-phase fault incidents is by a customer calling for having partial lights out. The automatic detection of these incidents may provide time-savings and reliability benefits, resulting in improved SAIDI/Customer Average Interruption Duration Index (CAIDI) metrics.

The AMI WFM application can also be leveraged to identify distribution transformers experiencing issues or that are highly likely to fail. With this ability, issues can be addressed before a transformer failure, providing the opportunity to mitigate potential wildfires and prevent reliability and public safety issues. Lastly, the project found that voltage anomalies occurred before a tree branch caused a fault. This offers the possibility of using AMI data to identify vegetation incursion and predict vegetation-related faults.

8.1.2.8.2 Early Fault Detection (WMP.1195)

Utility Initiative Tracking ID

WMP.1195

Overview of the Activity

Electrical equipment failures can cause significant damage, customer and employee safety impacts, high costs of repair, and extended outages to customers. Equipment failures, specifically those in fire-prone areas, can cause significant loss of life and property and should be avoided at all costs. Through years of research and development, SDG&E has developed, alongside its strategic vendor partnerships, ways to successfully detect what are known as incipient faults on the system with enough time to locate and potentially fix or replace equipment prior to it permanently failing. These incipient faults occur on failing pieces of equipment long before they fail violently and cause damage to the surrounding area. Recent advances in power quality, relaying, radio frequency, and other technologies have made it possible for utilities to identify and predict failures long before they occur.

The EFD Program (WMP.1195) aims to utilize these technologies to detect and prevent significant equipment failures in order to address fire risk while also gaining the benefits of reducing customer forced outages.

Technologies implemented by the EFD Program include:

- ARFS
- PQ Meters

Advanced Radio Frequency Sensors (ARFS)

ARFS use radio frequency monitoring of partial discharge from primary conductors to find, replace, and/or repair damaged components before they ultimately fail. Sensors are installed for each phase at 4-km intervals along a circuit extending from just outside the substation to the end of its furthest branches. Data is collected every second and backhauled on commercial cell communication networks to web servers. Software analysis eliminates spurious signals and isolates signals which are generated by the electrical facilities. Comparing the timing of the arrival of the signals at two adjacent installations (nodes) allows the location of the equipment generating the signal to be determined within 10 meters on the path between the nodes. The developer analyses the data and provides monthly reports showing low-medium-high risk ratings for each structure on the path, allowing targeted inspections of the facilities to find the damaged equipment generating the signal.

The objective is to identify components of the electrical system that are deteriorating. For example, an aging insulator that is beginning to "track" from the conductor to the crossarm. The sensors find damage that is much more subtle than what is normally found in traditional visual inspections.

PQ Meters

The PQ Meter Deployment, Replacement, and Expansion portion of the EFD Program represents the continued deployment of PQ meters which can remotely monitor, capture, and transmit high-resolution electric system data supporting electric transmission, distribution, and substation asset management, operations, power quality investigations, distributed energy integration, reliability improvement, fire risk reduction, fault location, and predictive fault analytics. Applications are being evaluated which will have a direct positive impact on system reliability, customer service, fire risk reduction, and asset management.

These projects provide expansion to the PQ monitoring system (PQ Nodes) and associated communication and back-office systems. Goals of the project are to:

- Expand monitoring capability to circuits and field locations
- Provide field wiring and network connections to existing monitors
- Upgrade existing PQ nodes and support equipment
- Install new IT integration and interface for new equipment
- Install field and substation relay and communication systems
- Install new PQ support communication equipment
- Provide time synchronization for existing monitors

The PQ monitoring system provides the following benefits:

- Provides distribution, transmission, and substation system health information, including RMS voltage, voltage and current transient events, system harmonics (including spectra), real and reactive power flow, power factor, and flicker
- Provides logging and notification for events occurring on transmission, distribution, and customer systems that are perceptible at the distribution substation and customer locations
- Provides advanced analytics processes, including incipient fault detection (aka, fault anticipation or predictive fault analysis) and advanced fault locating
- Provides a data source with analytics for historical events and steady state trends
- Provides data collected via the substation PQ monitoring system that is regularly utilized by several groups, including Commercial and Industrial (C&I) Services, Electric Transmission, and Distribution Engineering and Planning

Continued deployment of PQ meters that can remotely monitor and capture data will support transmission, distribution, and substation asset management, fire risk reduction, Distributed Energy Resources (DER) integration, reliability enhancements, customer service, and power quality investigations. Use cases under development will support momentary or incipient fault detection and advanced fault locating.

Impact of the Activity on Wildfire Risk

Though the EFD Program (WMP.1195), damaged components can be identified before they catastrophically fail causing sparks, wire downs or outages that could result in an ignition. ARFS and PQ hardware is being installed on older circuits that are not expected to be significantly hardened in the next few years. One of the advantages of the ARFS technology is that the sensors are mounted 30 inches from the primary conductor so there is no contact with high voltage other than the small 1 kilovolt-ampere (kVA) transformer to power the control unit.

The ignitions reduced by 2025 was calculated using the 5-year average risk events. The 5-year average ignitions, the assumed effectiveness of 72 percent, and the number of planned EFD installations for the WMP timeframe. The mitigation will have an estimated 72 percent reduction in ignitions based on the technology and what the product is designed to accomplish. Based on this data, a reduction of 0.45 and 0.24 ignitions in Tier 3 and Tier 2, respectively, are expected by the end of 2025. Calculations are shown in SDG&E Table 8-7.

SDG&E Table 8-7: Risk Reduction Estimation for Early Fault Detection

Calculation Component	Component Value
Risk Events Tier 3-5 yr avg (2017-2021)	104
Risk Events Tier 2-5 yr avg (2017-2021)	114.8
Risk Events 5 yr avg Ignition Tier 3	2.91%
Risk Events 5 yr avg Ignition Tier 2	2.55%
5 yr Avg Ignition Rate Tier 3	104 x 2.91% = 3.02
5 yr Avg Ignition Rate Tier 2	114.8 x 2.55% = 2.93
Ignition reduction estimate Tier 3	3.02 x 72% = 2.1776
Ignition reduction estimate Tier 2	2.93 x 72% = 2.1082

Calculation Component	Component Value
Mitigation Effectiveness	72%
Total units In The Network Tier 3	420
Total units In The Network Tier 2	810
Actuals to be repaired or replaced Tier 3	86
Actuals to be repaired or replaced Tier 2	94
Ignition Reduced Tier 3	(86 ÷ 420) x 2.1776 = 0.44589
Ignition Reduced Tier 2	(94 ÷ 810) x 2.1082 = 0.244655
Total Ignition reduced	0.44589 + 0.244655 = 0.6905

Impact of the Activity on PSPS Risk

The EFD Program (WMP.1195) focuses on reducing the risk of wildfire. It does not have a quantifiable PSPS risk reduction.

Updates to the Activity

The EFD Program (WMP.1195) began as a 2-year demonstration project and transitioned to a regular project in mid-2022. The project began installation of the new fourth-generation ARFS control units in late 2022. The initial five circuits have third-generation ARFS. Third-generation ARFS can monitor 4 percent of each second compared to 96 percent of each second for fourth-generation units. The additional data generated by the fourth-generation ARFS will allow detection of damage earlier and in less time.

Initial deployment used one cell provider which resulted in some difficulty locating sufficient cell signal to place nodes at the far end of branches. New cell signal detection equipment is now being used to field cell signals from all three large commercial networks, allowing more optimal placement of ARFS units using the network with the best signal. SDG&E plans to continue with ARFS installation and Power Quality meters on 30 circuits within the HFTD areas, with emphasis in tiers 2 and 3.

A significant transition was made to solar power for most of the ARFS installations which will eliminate any added connection to the primary conductors for those locations. Some locations not suitable for solar still require one or two connections for a small transformer.

The use of more sophisticated analytic tools is being investigated to gain more value from the data generated by the ARFS units.

8.1.2.8.3 Distribution Communications Reliability Improvements (WMP.549)

Utility Initiative Tracking ID

WMP.549

Overview of the Activity

The current communication system within the HFTD does not have the bandwidth to support some of the technologies deployed as wildfire mitigations, including APP (WMP.463) and FCP. In addition, there are gaps in coverage of third-party communication providers in the rural areas of eastern San Diego County that limit the ability to communicate with field personnel during RFW crew deployments and EOC activations.

To mitigate this risk, the DCRI Program (WMP.549) was developed to deploy a privately-owned LTE network using licensed radio frequency spectrum, enhancing the reliability of the communication network. A reliable communication network is necessary for many initiatives that require continuous communication.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

Impact of the Activity on Wildfire Risk

This initiative does not have a Risk Reduction Estimation because it is foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

Impact of the Activity on PSPS Risk

This initiative does not have a Risk Reduction Estimation because it is foundational to supporting wildfire mitigation efforts. Quantifying a Risk Reduction Estimation would be difficult and not beneficial because it cannot be directly tied to reducing a risk driver and measuring the effectiveness of that reduction.

Updates to the Activity

Updates made to the DCRI Program (WMP.549) in 2022 include:

- Ongoing Spectrum clearing for second Spectrum licensing
- Ongoing radio frequency design and analysis in the HFTD
- Continued development of site design standards for quicker designs and deployments
- Ongoing siting surveys, land rights, and environmental analysis
- Continued community outreach and communications
- Completion of 22 base stations
- Ongoing use case testing and validation

Enhancements in the 2023 to 2025 WMP cycle will include installations of additional base stations.

As the DCRI Program progresses, initial build sites will be analyzed, and deployment strategies will be adjusted based on the analysis.

In alignment with the proposed settlement agreement with Public Advocates Office in SDG&E's pending GRC, SDG&E is reducing the scope of this program.

Most sites planned for base station installation have engineered steel foundation poles that will have telecommunication antennas at the top of the pole and electric (12 kV and below) attachments in the middle of the pole. Poles are currently undergoing standardization, and development of pole specifications, including workspace, operational, and manufacturing requirements, has taken longer than expected. To complete the pole standardization, three pilot sites were selected and pole orders were placed at the end of 2023. In 2024, construction of these three pilot sites and standardization of pole designs is expected to be completed, which will accelerate the initiative in 2025 and beyond. In addition, process improvements with substation and transmission facility engineering and operations groups are being developed to ensure proper design and construction.

Workplan modifications will delay improvements expected from the SDG&E-owned private LTE network backbone that supports some Advanced Protection initiatives including Falling Conductor Protection (FCP) and Early Fault Detection (EFD). FCP and EFD work will continue to be deployed in the interim and will be enhanced once the LTE backbone is completed. This change is not expected to impact expected wildfire risk reduction within the 2023-2025 WMP cycle.

8.1.2.9 Line Removal (in HFTD)

8.1.2.9.1 Utility Initiative Tracking ID

N/A – Line removals are related to Strategic Undergrounding (WMP.473), Covered Conductor Installations (WMP.455), or Overhead Traditional Hardening and as such, do not have a separate Utility Initiative Tracking ID.

8.1.2.9.2 Overview of the Activity

SDG&E proactively removes overhead lines as part of the Strategic Undergrounding Program (WMP.473) and occasionally during certain overhead hardening initiatives such as covered conductor installations. For example, if a circuit segment is planned to be undergrounded, all associated overhead infrastructure would be removed. For covered conductor installations, overhead distribution lines are removed from service only if they are no longer in use.

SDG&E does not track Line removal in the HFTD as a reportable metric because these mileages are already associated with the new installations under other programs. SDG&E has recently begun to quantify line miles removed as a result of underground and overhead hardening initiatives; however, because the GIS mapping system is 'as-built', it is not possible to retroactively quantify these line miles removed.

8.1.2.9.3 Impact of the Activity on Wildfire Risk

Impacts to wildfire risk associated to line removals are summarized in the following initiatives:

- Strategic Undergrounding Program (WMP.473) (see Section 8.1.2.2)
- Covered Conductor Program (WMP.455) (see Section 8.1.2.1)
- Overhead Traditional Hardening (WMP.475 and WMP.543) (see Section 8.1.2.5)

8.1.2.9.4 Impact of the Activity on PSPS Risk

Impacts to PSPS risk associated to line removals are summarized in the following initiatives:

- Strategic Undergrounding Program (WMP.473) (see Section 8.1.2.2)
- Covered Conductor Program (WMP.455) (as a future enhancement) (see Section 8.1.2.1)

8.1.2.9.5 Updates to the Activity

No updates since the last WMP submission.

8.1.2.10 Other Grid Topology Improvements to Minimize Risk of Ignitions

8.1.2.10.1 Avian Protection Program (WMP.972)

Utility Initiative Tracking ID

WMP.972

Overview of the Activity

The Avian Protection Program (WMP.972) involves installing avian protection equipment on distribution poles in the service territory to prevent electrocution of birds and to facilitate compliance with Federal and State Laws. The Program is aimed at improving reliability and reducing the risk of faults and wire-down events associated with avian contact that can lead to ignitions. Avian protection equipment will be installed concurrently with other asset replacement initiatives across the HFTD such as hot line clamp replacements (WMP.464), fuse replacements, and lightning arrester replacements (WMP.550).

Impact of the Activity on Wildfire Risk

Animal contacts represent a total of 7.8 percent of overall risk events in the HFTD between 2017 and 2021. Reducing the number of animal contacts by installing avian protection will, in turn, reduce the likelihood of subsequent ignitions from occurring. The estimated percent reduction in wildfire ignitions due to the installation of avian covers is 90 percent. This is based on field observations in the Tier 3 area.

The ignitions reduced by 2025 was calculated using the 5-year average risk events caused by animal contact, the 5-year average ignitions caused by animal contacts, and number of planned Avian Protection installations for the WMP timeframe. Based on this data, a reduction of 0.004 and 0.003 ignitions in Tier 3 and Tier 2, respectively, are expected by the end of 2025. Calculations are shown in SDG&E Table 8-8.

SDG&E Table 8-8: Risk Reduction Estimation for Avian Covers

Calculation Component	Component Value
Animal Contact Tier 3-5 yr avg (2017-2021)	23.2
Animal Contact Tier 2-5 yr avg (2017-2021)	26.2
Animal Contact Non-HFTD 5-yr avg (2017-2021)	34.8
Animal Contact 5-yr avg Ignition Tier 3	0.8
Animal Contact 5-yr avg Ignition Tier 2	0.6
Animal Contact 5-yr avg Ignition Non-HFTD	0.2
5-yr Avg Ignition Rate Tier 3	3.45%
5-yr Avg Ignition Rate Tier 2	2.29%
5-yr Avg Ignition Rate Non-HFTD	0.57%
Total Avian Protection in the Network Tier 3	39,575
Total Avian Protection in the Network Tier 2	46,955
Total Avian Protection in the Network Non HFTD	136,835
Avian Protection actuals to be repaired or replaced Tier 3	240

Calculation Component	Component Value
Avian Protection actuals to be repaired or replaced Tier 2	240
Avian Protection actuals to be repaired or replaced Non HFTD	120
Mitigation Effectiveness	90%
Ignition Reduced Tier 3	0.8 x (240 ÷ 39,575) x 90% = 0.004
Ignition Reduced Tier 2	0.6 x (240 ÷ 46,955) x 90% = 0.00276
Ignition Reduced Non-HFTD	0.2 x (120 ÷ 136,835) x 90% = 0.000158
Total Ignition reduced	0.004 + 0.00276 +0.000158 = 0.007

Impact of the Activity on PSPS Risk

The purpose of the Avian Protection Program (WMP.972) is to reduce the risk of wildfire. This program does not affect the PSPS risk.

Updates to the Activity

Between 2023-2025, SDG&E plans to install avian protection equipment at 1,000 locations in the HFTD.

8.1.2.10.2 Strategic Pole Replacement Program (WMP.1189)

Utility Initiative Tracking ID

WMP.1189

Overview of the Activity

The Strategic Pole Replacement Program (WMP.1189) will focus on the replacement of gas-treated poles in fire prone areas of the service territory, including Tier 2 and 3 of the HFTD and the WUI. The purpose of this program is to target high-risk poles located throughout the service territory that are gas treated (also known as Cellon treatment) and are set in concrete and steel reinforced, steel reinforced and set in soil, or set in soil, and are not being addressed by other programs such as the Covered Conductor Program (WMP.455) or the Strategic Undergrounding Program (WMP.473). These poles are nearing the end of their useful life and are known to have a higher failure potential. Gas treated poles have a higher propensity for dry rot due to the pole's interaction with the moisture in the soil, and poles set in concrete are more difficult to inspect and determine the integrity of the pole. The average age of these gas treated poles is nearing 50 years.

The program will have multiple risk categories and will be prioritized based on these categories.

- Phase 1 (approximately 85 poles): Pole set in concrete and steel reinforced or pole set in concrete and not steel reinforced
- Phase 2 (approximately 58 poles): Pole set in soil and steel reinforced
- Phase 3 (approximately 1,379 poles): Pole set in soil and not steel reinforced
- Total poles in scope: Approximately 1,522 poles

Phase 1 poles would be addressed first, followed by Phase 2 then Phase 3. However, permitting, land rights, environmental mitigation, customer concerns, or a combination of these factors will drive the ultimate schedule on each pole's replacement. Where feasible, poles will be bundled together in a single work package to minimize the impact to the community and gain efficiency in the design, environmental, permitting, land rights, and construction process. In most cases a single work order package will bundle poles that are adjacent or within a few spans of each other and will require similar land rights, permitting, and/or land rights.

Impact of the Activity on Wildfire Risk

The ignitions reduced by 2025 were calculated using the 5-year average risk events caused by pole damage or failure. Based on this data, a reduction of 0.025 and 0.05 ignitions in Tier 3 and Tier 2, respectively, are expected by the end of 2025. Calculations are shown in SDG&E Table 8-9.

SDG&E Table 8-9: Risk Reduction Estimation for the Strategic Pole Replacement Program

Calculation Component	Component Value
Pre-Mitigation Average Numbers of Faults Tier 3	14.4
Pre-Mitigation Average Numbers of Faults Tier 2	12.6
Pre-Mitigation Average Numbers of Faults Non HFTD	19.6
Average Ignition Rate Tier 3	2.91%
Average Ignition Rate Tier 2	2.56%
Average Ignition Rate Non HFTD	1.13%
Numbers of Pre-Mitigation Ignition Tier 3	14.4 x 2.91% = 0.41904
Numbers of Pre-Mitigation Ignition Tier 2	12.6 x 2.56% = 0.32256
Numbers of Pre-Mitigation Ignition Non HFTD	19.6 x 1.13% = 0.22148
Mitigation Effectiveness Estimate (%)	100%
Ignition Reduction Estimate Tier 3	0.41904 x 100% = 0.41904
Ignition Reduction Estimate Tier 2	0.32256 x 100% = 0.32256
Ignition Reduction Estimate Non HFTD	0.22148 x 100% = 0.22148
Poles Replacement Tier 3	115
Poles Replacement Tier 2	302
Poles Replacement Non HFTD	110
Numbers of Total Poles to be Replaced Tier 3	1940
Numbers of Total Poles to be Replaced Tier 2	1940
Numbers of Total Poles to be Replaced Non HFTD	1940
Total Ignition Reduced Tier 3	(115 ÷ 1940) x 0.41904 = 0.02484
Total Ignition Reduced Tier 2	(302÷ 1940) x 0.32256 = 0.050213
Total Ignition Reduced Non HFTD	(110 ÷ 1940) x 0.22148 =0.012558
Total Ignition Reduced	0.02484 + 0.050213 + 0.012558 = 0.087611

Impact of the Activity on PSPS Risk

The purpose of the Strategic Pole Replacement Program (WMP.1189) is to reduce the risk of ignitions and wildfire. This program does not affect the PSPS risk.

Updates to the Activity

Through the CMP and grid hardening initiatives, an increase in the scope, and therefore target, of this initiative was identified. In addition to replacing cellon-treated wood poles, this initiative will also target poles that require pole loading remediation.

8.1.2.11 Other Grid Topology Improvements to Mitigate or Reduce PSPS Events

8.1.2.11.1 PSPS Sectionalizing Enhancement Program (WMP.461)

Utility Initiative Tracking ID

WMP.461

Overview of the Activity

The PSPS Sectionalizing Enhancement Program (WMP.461) installs switches in strategic locations, improving the ability to isolate high-risk areas for potential de energization. For example, switches are installed on circuits that have significant sections underground, allowing customers with this lower-risk infrastructure to remain energized during weather events. Another example is combining weather stations with sectionalizing devices to de-energize only sections of circuits that are experiencing extreme wind events.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

Impact of the Activity on Wildfire Risk

The purpose of the PSPS Sectionalizing Enhancement Program (WMP.461) is to reduce the risk of PSPS. This program does not affect the Wildfire risk.

Impact of the Activity on PSPS Risk

By increasing the number of remotely operated sectionalizing devices on higher risk circuits, SDG&E can reduce the number of customers that have the potential to be impacted by a PSPS event or potentially reduce the duration of de-energization based on local wind events. Between 2023 and 2025 it is estimated that these new sectionalizing devices could impact over 17,500 customers.

Updates to the Activity

No changes were made to this Program in 2022 and none are expected to be made in 2023.

8.1.2.11.2 Standby Power Program (Fixed Backup Power: Residential/Commercial) (WMP.468)

Utility Initiative Tracking ID

WMP.468

Overview of the Activity

The Standby Power Program (WMP.468), which is an umbrella program that includes several other programs, targets customers and communities that will not directly benefit from other grid hardening programs. These customers reside in the backcountry and are generally widely distanced from one another, therefore traditional grid hardening initiatives will not reduce potential PSPS exposure. The Standby Power Program consists of the Fixed Backup Power (FBP) Program targeting residential customers, FBP Program targeting commercial customers, and the Mobile Home Park Resilience Program (MHRP) which targets mobile home park clubhouses.

Standby Power Program was introduced to assist rural customers in the HFTD that may not benefit from near- or long-term traditional hardening initiatives. Other hardening initiatives in these communities would be ineffective and costly, with no guarantee that power would not be shut off during a PSPS event. Instead, providing fixed standby generators is the most efficient remedy for certain rural customers that are likely to experience PSPS events.

Customers are identified based on meter, circuit and PSPS event exposure. Outreach letters and communication are sent to customers inviting them to participate and, depending on site requirements, feasibility, and cost, a customer could receive a fixed installation backup generator, a business could receive a critical facility generator on a temporary basis during an active PSPS event, or a clubhouse or central community building at a mobile home park could receive a solar panel and battery backup system to provide resilient access to electricity during power outages, particularly during a PSPS event. The program manages site permitting, construction, and final inspection to ensure the equipment is installed properly.

Figure 8-7 shows the display the FPB installation at a mobile home park community.

Figure 8-7: FPB Installation at Mobile Home Park Community

Impact of the Activity on Wildfire Risk

The purpose of the Standby Power Program (WMP.468) is to reduce the impact of PSPS consequences, namely the loss of power. This program does not directly affect Wildfire risk.

Impact of the Activity on PSPS Risk

PSPS events can have negative customer impacts and should be limited as much as feasible to the specific areas that are experiencing extreme risk. This is especially important for customers who may require medical devices to be powered 24 hours a day, 7 days a week. The Standby Power Program (WMP.468) does not reduce PSPS risk but reduces the impact of PSPS for vulnerable customers. Through 2022, the Standby Power Program provided backup power solutions to approximately 820 residential and nine commercial customers thereby reducing PSPS consequences. For 2023, the program plans for an additional participation of approximately 300 residential and six commercial customers, bringing the estimated total to 1,135. This number is calculated based on how many customers would receive generators and is used to estimate the reduction in PSPS impacts to calculate the RSE. Because the generators provided to customers as a part of this program are whole-facility solutions that are expected to keep the customers energized throughout a PSPS event, the effectiveness of the mitigation is estimated to be 100 percent.

Updates to the Activity

Enhancements and progress made in 2022 include:

Residential:

- Enhanced coordination between the program team and the hardening analysis teams to identify communities that may benefit from fixed backup power solutions
- Increased system automation to streamline customer application processing and workflow tracking
- Strengthened relationship with County to support permitting and inspection processes
- Targeted all MBL customers in HFTD Tier 2 and Tier 3 of the HFTD that experienced a PSPS event between 2019 and 2021

Updates for 2023:

Residential:

- Evaluate non-fossil fuel backup battery technology options for residential customer installations
- Continue to provide fixed backup power solutions to residential and commercial customers who experience frequent PSPS

Commercial:

- Strengthen the process of promoting participation and delivering resources in partnership with tribal community partners
- Develop plans to offer to additional AFN population and tribal communities

Updates for 2024 and 2025:

In alignment with the proposed settlement agreement with Public Advocates Office in SDG&E's pending GRC, SDG&E is reducing the scope of this program.

In 2024, the Standby Power Programs will reach their intended goal, including mitigations of over 1,200 residential customers and 19 commercial sites, and provide valuable strategic and operational lessons learned. In 2025, the programs will build on 2024 efforts to explore and evaluate additional mitigation approaches, continuing to support customer resilience while focusing on climate adaptation outcomes such as renewable backup power options. Program adjustments will be made to support these design enhancements and the 2025 target was adjusted accordingly.

8.1.2.11.3 Generator Grant Program (WMP.466)

Utility Initiative Tracking ID

WMP.466

Overview of the Activity

The Generator Grant Program (GGP) (WMP.466) focuses on enhancing resiliency among the most vulnerable customer segments to enable access to electricity for medical devices and critical appliances during a PSPS event. This program was previously referred to as the Resiliency Grant Program.

The GGP offers portable backup battery units with solar charging capacity to customers, leveraging cleaner, renewable generator options to give vulnerable customers a means to keep small devices and appliances charged and powered during PSPS events. The GGP, launched in 2019, focuses on the needs of MBL and Life Support customers in addition to other customers with access and functional needs in Tiers 2 and 3 of the HFTD who have experienced an outage due to a PSPS event. Eligible customers are proactively contacted and educated about the GGP.

The Emergency Backup Battery Program is a reserve of backup batteries established specifically for expedited delivery during active PSPS events. These units are pre-charged and delivered within 1 to 4 hours of eligible requests to customers who call into SDG&E’s Customer Care Centers or 211 in need of emergency power backup that cannot be met through other AFN services such as hotel stays and accessible transportation. SDG&E also partners with Indian Health Councils to promote the availability of these backup battery units to vulnerable customers in tribal nation communities.

Impact of the Activity on Wildfire Risk

The purpose of the GGP (WMP.466) is to reduce the risk of PSPS. This program does not affect the Wildfire risk.

Impact of the Activity on PSPS Risk

The GGP (WMP.466) does not reduce PSPS risk but reduces the impact of PSPS for vulnerable customers. Through 2022, the GGP reduced the impact of PSPS events by providing portable backup battery units to approximately 4,700 customers. This represents the total number of customers who have received units, though a portion of these customers may have experienced subsequent changes in location, MBL standing, or other eligibility status. For 2023, the program plans for additional participation of approximately 1,000 customers, bringing the estimated total to 5,700. This number is calculated based on the count of eligible customers likely to request portable backup battery units and is used to estimate the reduction in PSPS impact to calculate the RSE. Because the generators provided to customers as a part of this program are not whole-facility solutions, the effectiveness of the mitigation is estimated to be 40 percent.

Updates to the Activity

Enhancements and progress made in 2022 include:

- Solidified a dedicated reserve of backup battery units to deliver during active PSPS events. This provides support to those qualified customers who have not yet participated in the program, as well as prior participants who have received a unit and need additional capacity.
- Expanded program to a broader audience to include AFN customers in Tiers 2 and 3 of the HFTD who have experienced a PSPS outage, ensuring those who are most vulnerable during PSPS events are captured, specifically:
    - Individuals with disabilities, those that are blind/low vision and deaf/hard of hearing
    - Those that are temperature-sensitive
    - Those that have self-identified as AFN
- Established an online request form to enable interested customers to learn more about the program and apply, ensuring all eligible customers have the opportunity to participate
- Reviewed additional product technologies for inclusion into the program
- Began contacting customers that have received a backup power unit in previous program years to provide key safety reminders regarding their usage, care and maintenance

Updates for 2023:

- Continue working with tribal community leaders and liaisons to ensure vulnerable customers are aware of the program
- Continue contacting customers with a backup power unit to provide key safety reminders regarding usage, care and maintenance

8.1.2.11.4 Generator Assistance Program (WMP.467)

Utility Initiative Tracking ID

WMP.467

Overview of the Activity

The Generator Assistance Program (GAP) (WMP.467) focuses on enhancing resiliencies for all customers who reside in Tiers 2 and 3 of the HFTD and may be impacted by PSPS events. While the GGP (WMP.466) addresses the needs of the most medically vulnerable and the Standby Power Program (WMP.468) focuses on customers that do not have other grid hardening initiatives planned in their area, the GAP expands resilience opportunities to the general market in Tiers 2 and 3 of the HFTD. This program was previously referred to as the Resiliency Assistance Program.

The GAP launched in 2020 and offers rebates for portable fuel generators and portable power stations to encourage customers to acquire backup power options to enhance preparedness and mitigate the impacts of PSPS. The target audience are customers who reside within Tiers 2 and 3 of the HFTD and have experienced at least one PSPS event since 2019. Eligible customers receive program materials via mail and email campaigns and are directed to an online portal to verify account information and learn more about the program. Upon verification, the program offers a $300 rebate to customers who meet the basic eligibility criteria of residing in an HFTD zone and experiencing a recent PSPS event. In addition, customers enrolled in the California Alternate Rates for Energy (CARE) program are eligible for an enhanced rebate amount of $450, providing a 70 to 90 percent discount on average portable generator models. The program also includes portable power stations and offers rebates of $100, with an additional $50 for CARE customers. The program provides the option for customers to receive one rebate for a fuel generator and one rebate for a portable power station to accommodate various backup power needs. To date, GAP has provided over 2,100 rebates. Customers may receive a rebate for a fuel generator as well as for a portable power station.

Impact of the Activity on Wildfire Risk

The purpose of the GAP (WMP.467) is to reduce the risk of PSPS. This program does not affect the Wildfire risk.

Impact of the Activity on PSPS Risk

The GAP (WMP.467) does not reduce PSPS risk but reduces the impact of PSPS for customers. Through 2022, GAP reduced the impact of PSPS events by providing rebates to approximately 2,100 customers. This represents the total number of customers who have received rebates, though a portion of these customers may have experienced subsequent changes in location or other eligibility status. A primary driver of a customer participating in this program and purchasing a backup power solution is the anticipation of power shutoff due to high winds, wildfire risk, or other weather emergency. In 2022, the number of anticipated power shutoffs was relatively low and therefore customer participation was also low. For 2023, the program plans for additional participation of approximately 700 customers, bringing the estimated total to 2,800. This number is based on how many customers are expected to purchase generators through the rebate program and is used to estimate the reduction in PSPS impact to calculate the RSE. Because generators purchased through this program vary depending on the customer’s preferences, the effectiveness of the mitigation is estimated to be 75 percent.

Updates to the Activity

Enhancements and progress made in 2022 include:

- Enhanced the program process and portal to provide rebates on purchases made at any retailer so customers have more choice and inventory options. Prior year rebates were limited to two major retailers
- Updated the qualified product list for fuel generators to only include models that are CARB compliant and have carbon monoxide sensor and auto shutoff
- Increased the rebate amount for portable power stations from $50 to $100 per customer and introduced an additional $50 rebate for CARE customers
- Promoted program to local agencies to spread awareness for qualified constituents

Updates for 2023:

- Continue to identify models that meet the program requirements and update the qualified product list
- Consider partnering more with CBOs and local agencies to promote the program's offerings.

8.1.2.12 Other Technologies and Systems not Listed Above

8.1.2.12.1 Utility Initiative Tracking ID

WMP.558

8.1.2.12.2 Overview of the Activity

The IMP (WMP.558) is foundational; this activity alone does not mitigate the risk of wildfire but is critical in understanding the overall wildfire risk in relation to SDG&E equipment assets. This activity, in conjunction with other foundational activities, allows for mitigation prioritization, the calculation of RSEs, and aids to effectively select and implement the right mitigations and controls to reduce the risk of wildfires.

The IMP has built processes to collect data from all internal stakeholders to track ignition and potential ignitions, perform root cause analysis of incidents in an effort to determine the exact cause of the failure, and detect patterns or correlations. When the cause of the failure is determined, the mode of failure is reported to the appropriate mitigation owner for remedy.

The program is managed by the IMP Manager within the FSCA.

8.1.2.12.3 Impact of the Activity on Wildfire Risk

The IMP (WMP.558) is a program foundational to supporting wildfire mitigation efforts. It has no direct impact on the risk of wildfire.

8.1.2.12.4 Impact of the Activity on PSPS Risk

The IMP (WMP.558) is a program foundational to supporting wildfire mitigation efforts. It has no direct impact on the risk of PSPS.

8.1.2.12.5 Updates to the Activity

This program was started in 2019, and has continued to build processes to mature. Data gathering processes and quality of the data are continually reviewed with enhancements implemented as soon as they are identified.

8.1.3 Asset Inspections

SDG&E's asset management and inspection programs are designed to promote safety for the general public, SDG&E personnel, and contractors by providing a safe operating and construction environment while maintaining system reliability. Inspection and maintenance programs identify and repair conditions and components to reduce potentially defective equipment on the electric system, minimizing hazards and maintaining system reliability. These programs continue to identify ways to improve the safety of the electric system. This includes developing new programs such as the evolving

DIAR Program (WMP.552) and supplementing existing programs such as patrol and detailed inspections with non-routine, risk-informed inspections.

SDG&E implements comprehensive, multi-faceted transmission and distribution inspection and patrol programs. These programs consist of detailed inspections, visual patrols, infrared inspections, and other various specialty patrols, inspections, and assessments. Inspections and patrols of all structures, attachments, and conductor spans are performed to identify facilities and equipment that may not meet PRC § 4292 and 4293 or GO 95 rules. OEIS Table 8-6 outlines transmission and distribution asset inspection programs by type.

OEIS Table 8-6: Asset Inspection Frequency, Method, and Criteria

Tracking ID	Type	Inspection Program	Frequency or Trigger	Method of Inspection per OEIS QDR Guidelines	Governing Standards & Operating Procedures
WMP.478 (8.1.3.1)	Distribution	Distribution Overhead Detailed Inspections	5 years	Ground	GO 165, 95
WMP.479 (8.1.3.2)	Transmission	Transmission Overhead Detailed Inspections	3 years	Ground	GO 165, 95 FAC-501-WECC
WMP.481 (8.1.3.3)	Distribution	Distribution Infrared Inspections	Risk-based	Ground	GO 165, 95
WMP.482 (8.1.3.4)	Transmission	Transmission Infrared Inspections	Annual	Aerial (helicopter) Ground	GO 165, 95
WMP.483 (8.1.3.5)	Distribution	Distribution Wood Pole Intrusive Inspections	10 years	Ground	GO 165, 95
WMP.1190 (8.1.3.6)	Transmission	Transmission Wood Pole Intrusive Inspections	8 years	Ground	GO 165, 95
WMP.552 (8.1.3.7)	Distribution	Drone Assessments	Risk-based in HFTD & WUI	Aerial - drone Ground	n/a
WMP.488 (8.1.3.8)	Distribution	Distribution Overhead Patrol Inspections	Annual	Ground	GO 165, 95
WMP.489 (8.1.3.9)	Transmission	Transmission Overhead Patrol Inspections	Annual	Aerial - helicopter	GO 165, 95 FAC-501-WECC
WMP.555 (8.1.3.10)	Transmission	Transmission 69kV Tier 3 Visual Inspections	Annual	Aerial - helicopter	GO 95
WMP.492 (8.1.3.11)	Substation	Substation Patrol Inspections	Monthly or Bi-monthly	Ground	GO 174

In general, priority levels for inspection findings are defined by GO 95, Rule 18 as shown in SDG&E Table 8-10. Correction timeframes are also established by GO 95, Rule 18 and are described in more detail in Section 8.1.7 Open Work Orders. Correction timeframes may be extended under reasonable circumstances per GO 95, Rule 18.

SDG&E Table 8-10: GO 95, Rule 18 Inspection Finding Priority Levels

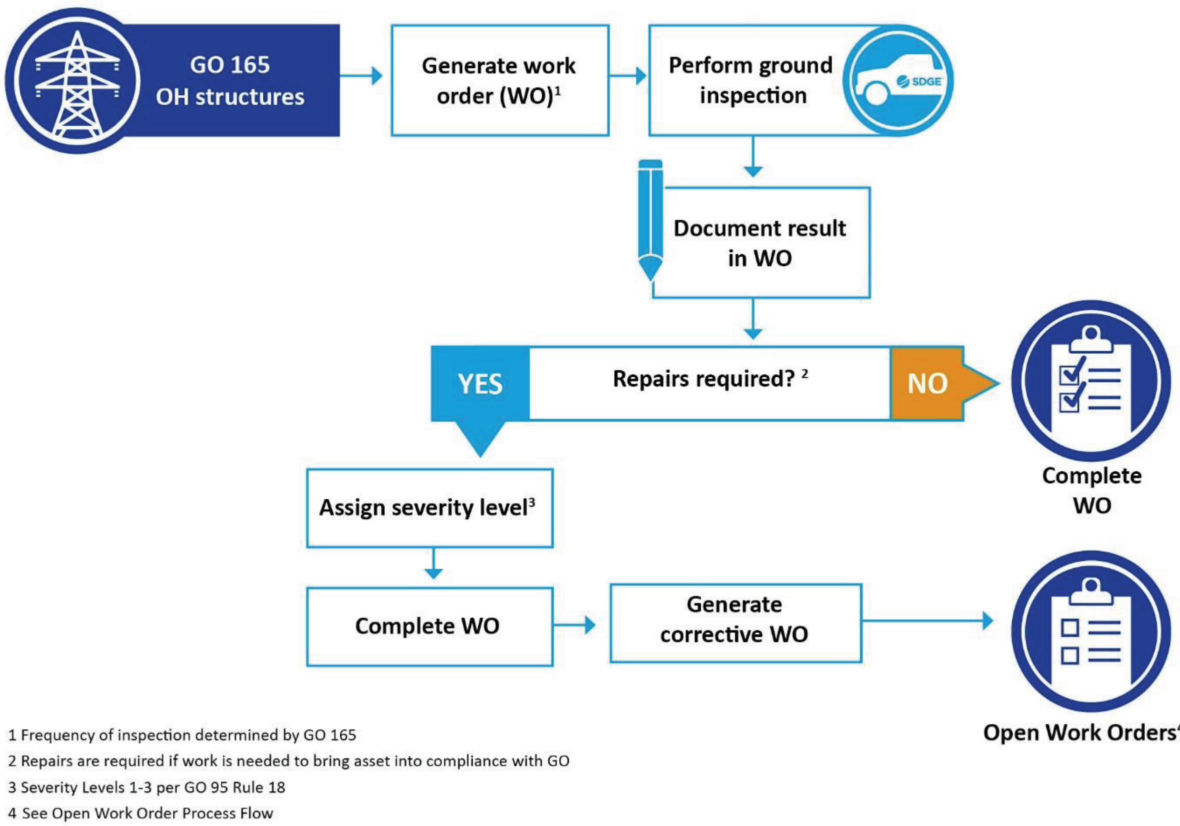
Priority Level	Definition
Level 1	Immediate safety and/or reliability risk with high probability for significant impact
Level 2	Variable (non-immediate high to low) safety and/or reliability risk
Level 3	Acceptable safety and/or reliability risk

8.1.3.1 Distribution Overhead Detailed Inspections (WMP.478)

GO 165 requires SDG&E to perform a service territory-wide inspection of its electric distribution system, generally referred to as the CMP (WMP.478). The CMP helps mitigate wildfire risk by providing additional information about the condition of the electric distribution system, including the HFTD. With this information, potential infractions can be addressed before they develop into issues.

GO 165 establishes inspection cycles and record-keeping requirements for utility distribution equipment. In general, utilities must patrol their systems once a year in urban areas and in Tier 2 and Tier 3 of the HFTD (see Section 8.1.3.8 Distribution Overhead Patrol Inspections (WMP.488). In addition to patrols, utilities must conduct detailed inspections at a minimum of every 5 years for overhead structures and sub-equipment. The 5-year detailed inspections of overhead facilities are mandated by GO 165. The corrective work resulting from detailed inspections is described in Section 8.1.7 Open Work Orders. Figure 8-8 outlines this process.

Figure 8-8: Distribution Detailed Overhead Inspections Process Flow



Per GO 165, detailed inspections of overhead facilities are currently completed on a 5-year cycle for all overhead structures, including those in the HFTD. Non-routine, ad hoc inspections may be conducted for operational or reliability purposes. Additionally, SDG&E prioritizes detailed inspections in the HFTD prior to fire season (as defined in Appendix A). Detailed inspections are also supplemented by risk-informed drone inspections as described in Section 8.1.3.7 Drone Assessments (WMP.552). There are no plans to change the frequency of this program. However, beginning in 2025, inspections performed in the WUI will be incorporated into the WMP reporting.

For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if there were no inspections or repairs within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD Tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided are calculated on an annual basis and can change depending on the inspection cycle. For 2023, an estimated 0.188 ignitions would occur if inspections and repairs were not completed in the prescribed timeframes as part of the 5-year detailed distribution inspection program (WMP.478). Calculations are shown in SDG&E Table 8-11.

SDG&E Table 8-11: Risk Reduction Estimation Methodology for the CMP

Calculation Component	Component Value
5-year average hit rate Emergency (0-3 days)	0.001
5-year average hit rate Priority (4-30 days)	0.001
5-year average hit rate Non-Critical	0.055
Fail Rate Emergency	48%
Fail Rate Priority	4.8%
Fail Rate Non-Critical	0.40%
2023 Projected Inspection Findings Tier 3	3 + 4 + 206 = 213
2023 Projected Inspection Findings Tier 2	6 + 7 + 403 = 416
Risk events Avoided Tier 3	(3 x 48%) + (4 x 4.8%) + (206 x 0.4%) = 2.456
Risk events Avoided Tier 2	(6 x 48%) + (7 x 4.8%) + (403 x 0.4%) = 4.828
Distribution Ignition rate Tier 3	2.91%
Distribution Ignition rate Tier 2	2.56%
Ignitions Avoided Tier 3	2.456 x 2.91% = 0.069
Ignitions Avoided Tier 2	4.828 x 2.56% = 0.119
Total ignitions avoided HFTD	0.119 + 0.069 = 0.188

The CMP was successfully completed in 2022. The Electric Safety and Reliability Branch of the CPUC also conducted an electric distribution audit of SDG&E's Beach Cities District on August 1-5, 2022. The results of the audit yielded 26 non-emergency, Level 2 maintenance items that were corrected immediately upon discovery.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

Challenges in performing detailed inspections are centered around access issues related to customers, difficult terrain, and labor resources.

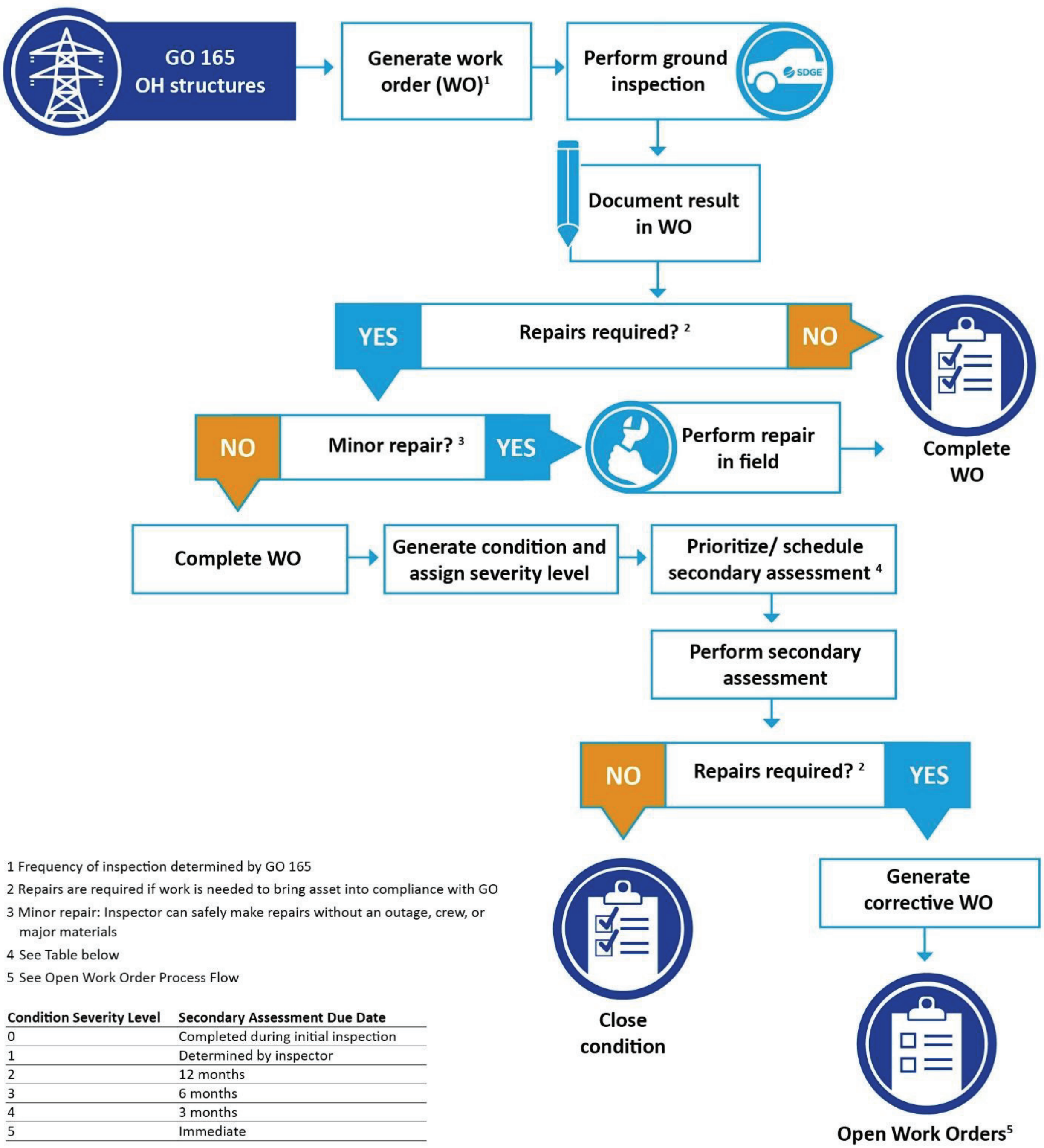
The CMP will continue in compliance with GO 165. Results from 2022 Light detection and ranging (LiDAR) inspections and high-definition imagery from drone inspections (discussed in the 2022 WMP Update) will be reviewed to provide feedback and enhance ground GO 165 detailed overhead visual inspections and patrols.

8.1.3.2 Transmission Overhead Detailed Inspections (WMP.479)

GO 165 requires SDG&E to perform a service territory-wide inspection of its electric transmission system, generally referred to as the CMP. The CMP helps mitigate wildfire risk by providing additional information about the condition of the electric transmission system, including the HFTD. With this information, potential infractions can be addressed before they develop into issues.

For detailed inspections, experienced internal linemen (patrollers) physically visit every structure scheduled for the year, looking at all components of the structure and conductor. By physically visiting the structures, patrollers can assess each structure for current and future maintenance requirements. As conditions are identified, internal severity codes are assigned to ensure supervisors properly prioritize assessment of conditions found. This prioritization considers the component identified, the location of the structure and surrounding terrain, and the severity of the condition. It also ensures that conditions are corrected in timeframes that meet or exceed GO 95 requirements. The corrective work resulting from detailed inspections is described in Section 8.1.7 Open Work Orders (WMP.1065). Figure 8-9 outlines the process for transmission detailed inspections.

Figure 8-9: Transmission Detailed Overhead Inspections Process Flow



1 Frequency of inspection determined by GO 165
2 Repairs are required if work is needed to bring asset into compliance with GO
3 Minor repair: Inspector can safely make repairs without an outage, crew, or major materials
4 See Table below
5 See Open Work Order Process Flow

Condition Severity Level	Secondary Assessment Due Date
0	Completed during initial inspection
1	Determined by inspector
2	12 months
3	6 months
4	3 months
5	Immediate

Detailed inspections are currently completed on a 3-year cycle for all overhead structures, including those in the HFTD. Inspections are prioritized and scheduled based on safety, reliability, and operational need.

For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs.

Failure rate calculations (i.e., how many risk events would occur within a year if there were no inspections or repairs within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average transmission ignition rate for risk events and ignitions in the HFTD was used to convert risk events avoided to ignitions avoided. The number of ignitions avoided is calculated on an annual basis and can change depending on the inspection cycle. For 2023, an estimated 0.15 ignitions would occur if inspections and repairs were not completed in the prescribed timeframes as part of the detailed transmission inspection program (WMP.479). Calculations are shown in SDG&E Table 8-12.

SDG&E Table 8-12: Risk Reduction Estimation Methodology for the Transmission Overhead Inspection Program

Calculation Component	Component Value
5-year average hit rate Emergency (0-3 days)	0
5-year average hit rate Priority (4-30 days)	0.016
5-year average hit rate Non-Critical	0.09
Fail Rate Emergency	48%
Fail Rate Priority	4.80%
Fail Rate Non-Critical	0.40%
2023 Projected Inspection Findings Tier 3	0 + 14 + 82 = 96
2023 Projected Inspection Findings Tier 2	0 + 23 + 132 = 155
Risk events Avoided Tier 3	0 x 48% + 14 x 4.8% + 82 x 0.4% = 1
Risk events Avoided Tier 2	0 x 48% + 23 x 4.8% + 132 x 0.4% = 1.632
Transmission Ignition rate HFTD	5.58%
Ignitions Avoided Tier 3	1 x 5.58% = 0.06
Ignitions Avoided Tier 2	1.632 x 5.58% = 0.09
Total ignitions avoided HFTD	0.06 + 0.09 = 0.15

SDG&E has a mature transmission inspection and maintenance program and participates in internal and external desktop and field audits with positive results. Industry standards and emerging technologies are also reviewed to ensure best maintenance practices are utilized. Detailed inspections were successfully completed in 2022.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

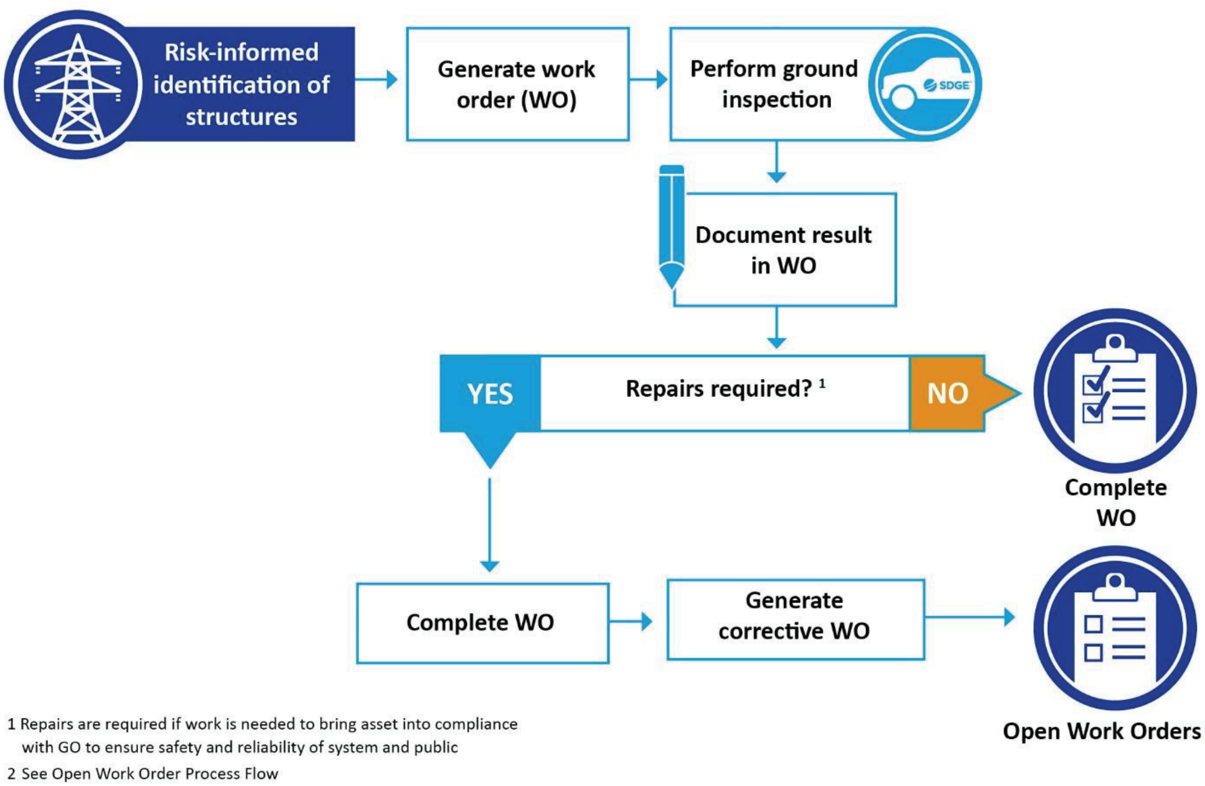
There were no roadblocks encountered during 2022 and there are no plans to change the scope or frequency of this program. However, beginning in 2025, inspections performed in the WUI will be incorporated into the WMP reporting.

Results of the DIAR Program (WMP.552), discussed in the 2022 WMP Update, revealed the effectiveness of this program with only a 1 to 3 percent findings rate.

8.1.3.3 Distribution Infrared Inspections (WMP.481)

Distribution Infrared Inspections (WMP.481) utilize infrared technology to examine the radiation emitted by connections to determine if there are potential issues with a connection before failure. Thermographers perform the ground inspection to capture and assess thermal imagery that may indicate an abnormality on the system. Findings are documented and required repair work is tracked through completion. The corrective work resulting from infrared inspections is described in Section 8.1.7 Open Work Orders. Figure 8-10 outlines the process for distribution infrared inspections.

Figure 8-10: Distribution Infrared Inspections Process Flow



The scope of this program includes approximately 300 distribution structures each year. In 2022, Tier 3 structures were selected based on higher wildfire consequence; however, minimal findings resulted. In 2023, structures will be selected considering HFTD Tier 2 location, recent reliability concerns, and subject matter expertise.

For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs.

Failure rate calculations (i.e., how many risk events would occur within a year if there were no inspections or repairs within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average distribution ignition rate for risk events and ignitions in the HFTD was used to convert risk events avoided to ignitions avoided. The ignitions avoided is calculated on an annual basis and can change depending on the inspection cycle. For 2023, an estimated 0.002 ignitions would occur if inspections and repairs were not completed in the prescribed timeframes as part of the Distribution Infrared Inspection Program (WMP.481). Calculations are shown in SDG&E Table 8-13.

SDG&E Table 8-13: Risk Reduction Methodology for Distribution Infrared Inspections Program

Calculation Component	Component Value
Fail Rate Emergency	48%
Fail Rate Priority	4.8%
Fail Rate Non-Critical	0.40%
2023Projected Inspection Findings Tier 3	0 + 0 + 0 = 0
2023 Projected Inspection Findings Tier 2	0 + 2 + 0 = 2
Risk events Avoided Tier 3	(0 x 48%) + (0 x 4.8%) + (0 x 0.4%) = 0
Risk events Avoided Tier 2	(0 x 48%) + (2 x 4.8%) + (0 x 0.4%) = 0.096
Distribution Ignition rate Tier 3	2.91%
Distribution Ignition rate Tier 2	2.56%
Ignitions Avoided Tier 3	0 x 2.91% = 0
Ignitions Avoided Tier 2	0.096 x 2.56% = 0.002458
Total ignitions avoided HFTD	0 + 0.002458 = 0.002458

Infrared inspections of Tier 2 and Tier 3 overhead structures and wires yielded limited findings. However, targeted inspections following undetermined outages or following a result of automated sensor indications proved infrared, combined with other inspection techniques, is useful in determining the source of an outage or a potential for future failure. Infrared inspections will continue on targeted overhead structures and will be expanded to investigate sensor indications of decreased system performance and undetermined outages.

This program exceeded its targets for 2022. Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

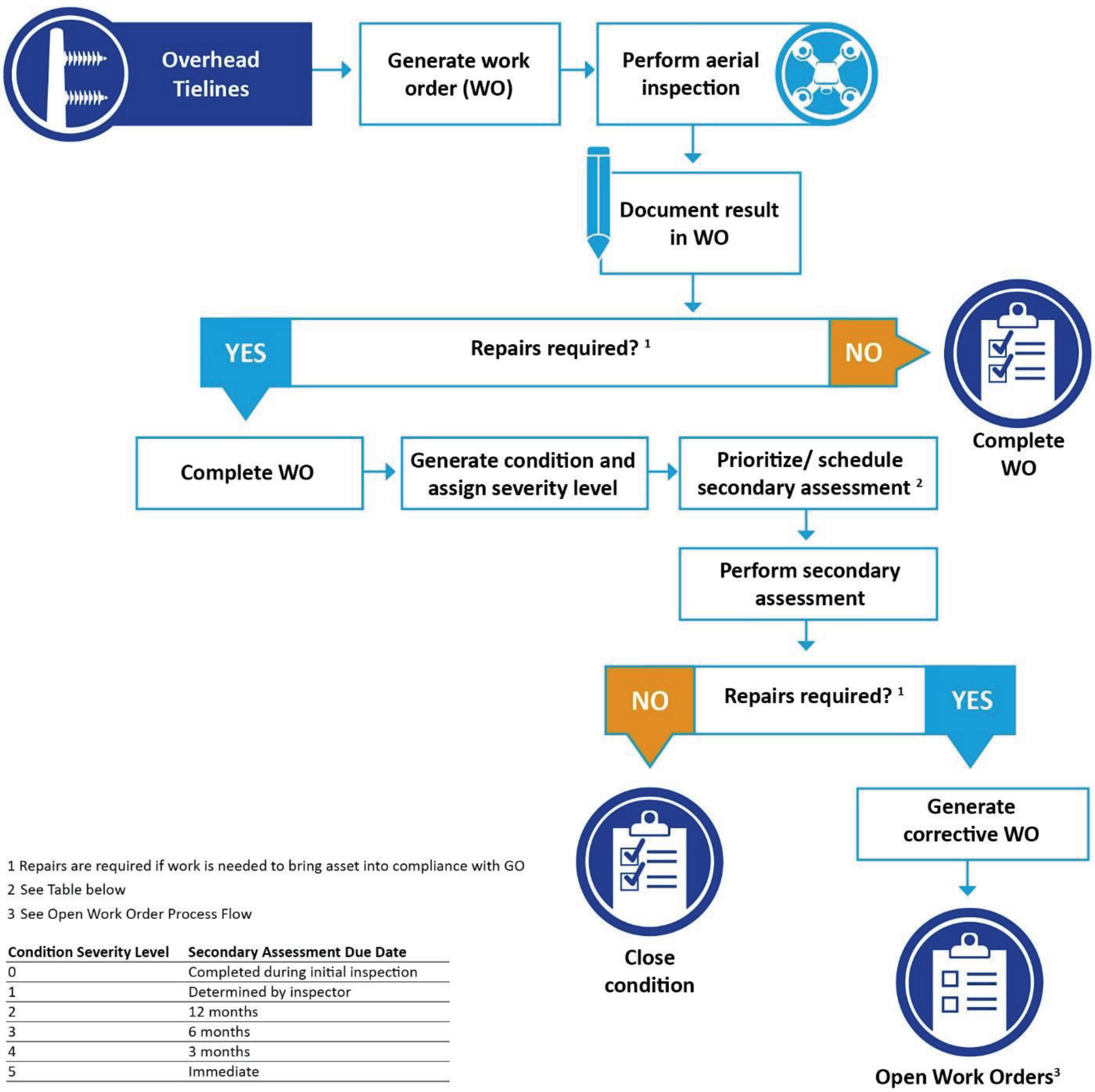
There were no roadblocks encountered during 2022 when performing infrared inspections and there are no plans to change the amount or frequency of inspections for this program. In 2020, the program was focused within Tier 3 and had very little findings due to minimal loading in the backcountry area; thus, in 2021 and 2022 inspections were refocused within Tier 2. Circuits were selected by each district's Operations & Engineering Manager and were based on high SAIDI values, Construction Supervisor feedback, and outage history. Circuits selected by the districts were then prioritized based on the total structure counts per Tier and were compared to circuits that had an infrared inspection already performed since 2020.

In 2024, the selection of structures for distribution infrared inspections will evolve into a risk-informed strategy. Prior to 2024, structures were selected based on the recommendations of subject matter experts with knowledge and experience of the service territory based on their perceived "risk". However, this method of inspection yielded a low findings rate of 0.2%. To promote efficiency, the initiative is therefore being optimized to target specific areas in the WUI that demonstrate higher loads during peak season (summer). In addition, a limited number of infrared inspections will be performed on covered conductor circuit segments to determine whether thermography is useful in identifying potential damage conditions to the covered conductor.

8.1.3.4 Transmission Infrared Inspections (WMP.482)

Transmission Infrared Inspections (WMP.482) utilize infrared technology to examine the radiation emitted by connections to determine if there are potential issues with a connection before failure. Findings are documented and required repair work is tracked through completion. Infrared patrols on transmission lines are most effective during higher loading conditions, therefore they typically begin in the warmer months prior to San Diego's wildfire season. As corrosion, rust, and other structural impacts may cause hotspots on structures and equipment, all energized transmission lines are included in the scope of this program. The corrective work resulting from infrared inspections is described in Section 8.1.7 Open Work Orders. Figure 8-11 outlines the process for transmission infrared inspections.

Figure 8-11: Transmission Infrared Inspections Process Flow



1 Repairs are required if work is needed to bring asset into compliance with GO

2 See Table below

3 See Open Work Order Process Flow

Condition Severity Level	Secondary Assessment Due Date
0	Completed during initial inspection
1	Determined by inspector
2	12 months
3	6 months
4	3 months
5	Immediate

Transmission infrared inspections are currently completed on an annual basis for all energized tielines, including those in the HFTD. Non-routine infrared inspections may be performed prior to weather events based on meteorological data. Wind speed, FPI, and other factors are also analyzed to prioritize inspections prior to RFW or other events.

For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs.

Failure rate calculations (i.e., how many risk events would occur within a year if there were no inspections or repairs within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average Transmission ignition rate for risk events and ignitions in the HFTD was used to convert risk events avoided to ignitions avoided. The ignitions avoided is calculated on an annual basis and can change depending on the inspection cycle. For 2023, an estimated 0.00 ignitions would occur if inspections and repairs were not completed in the prescribed timeframes as part of Transmission Infrared Inspections (WMP.482). Calculations are shown in SDG&E Table 8-14.

SDG&E Table 8-14: Risk Reduction Estimation for Transmission Infrared Inspections

Calculation Component	Component Value
Fail Rate Emergency	48%
Fail Rate Priority	4.80%
Fail Rate Non-Critical	0.40%
2023 Projected Inspection Findings Tier 3	0 + 0 + 0 = 0
2023 Projected Inspection Findings Tier 2	0 + 0 + 0 = 0
Risk events avoided Tier 3	(0 x 48%) + (0 x 4.8%) + (0 x 0.04%) = 0
Risk events avoided in Tier 2	(0 x 48%) + (0 x 4.8%) + (0 x 0.04%) = 0
Transmission ignition rate HFTD	5.58%
Ignitions avoided Tier 3	0 x 5.58% = 0
Ignitions avoided Tier 2	0 x 5.58% = 0
Total ignitions avoided HFTD	0 + 0 = 0

SDG&E has a mature transmission inspection and maintenance program and participates in internal and external desktop and field audits with positive results. Industry standards, emerging technologies are also reviewed to ensure best maintenance practices are utilized.

This program was successfully completed in 2022. Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

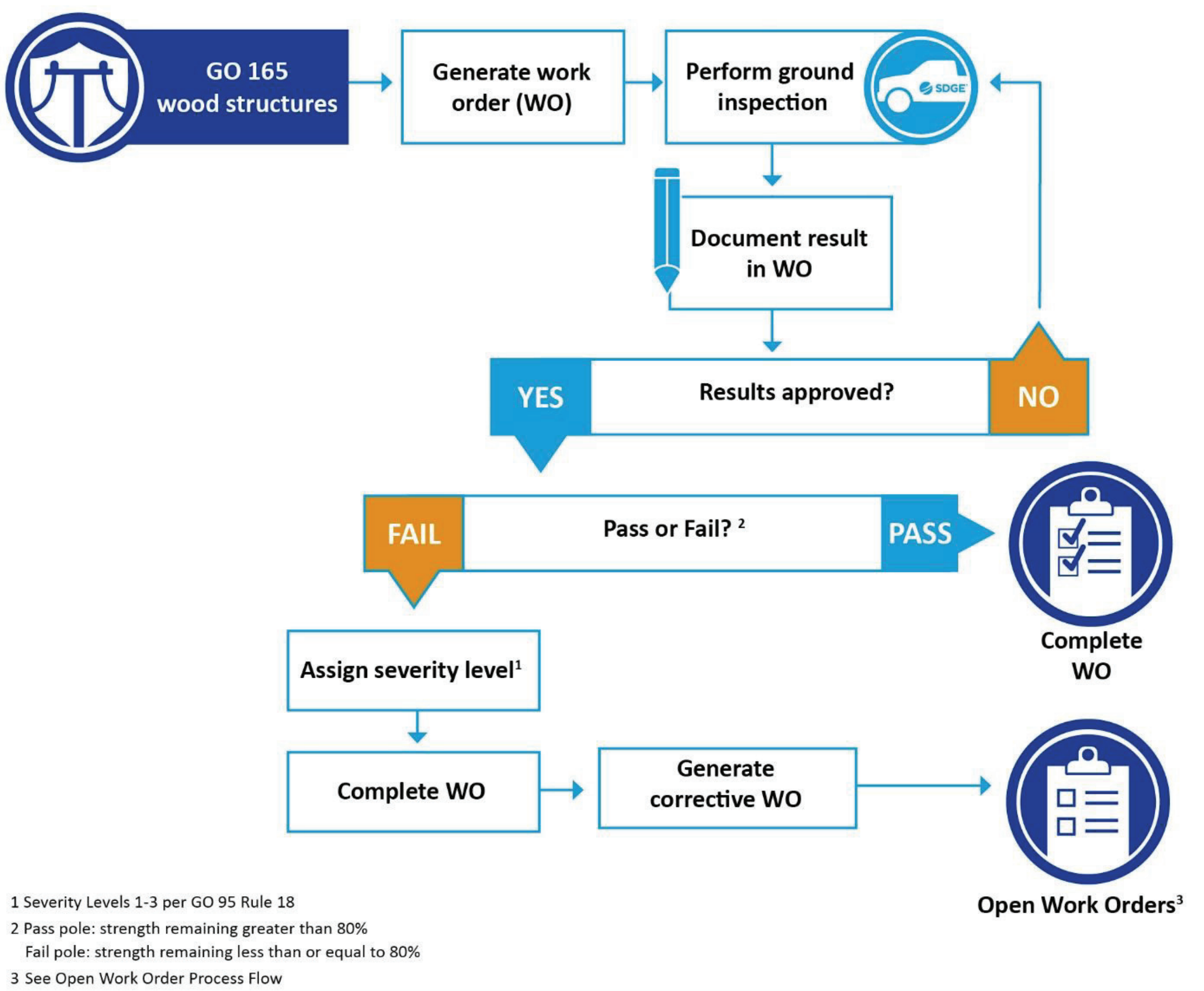
There were no roadblocks encountered during 2022 and there are no plans to change the scope or frequency of this program. However, beginning in 2025, inspections performed in the WUI will be incorporated into the WMP reporting.

8.1.3.5 Distribution Wood Pole Intrusive Inspections (WMP.483)

GO 165 requires all wood poles over 15 years of age to be intrusively inspected within 10 years and all poles which previously passed intrusive inspection to be inspected intrusively again on a 20-year cycle. Distribution wood pole intrusive inspections (WMP.483) are performed on a 10-year cycle.

An intrusive inspection typically involves an excavation around the pole base and/or a sound and bore of the pole at ground-line. Depending on the cavities found or the amount of rot observed, an estimate of the remaining pole strength is determined utilizing industry-wide standards. Depending on the severity of the deterioration, the pole either passes inspection with greater than 80 percent strength remaining or is replaced. The corrective work for replacement is described in Section 8.1.7 Open Work Orders. Figure 8-12 outlines the wood pole intrusive inspection process.

Figure 8-12: Wood Pole Intrusive Inspections Process Flow (Transmission and Distribution)



Distribution Wood Pole Intrusive inspections are currently performed on a 10-year cycle. Non-routine intrusive inspections may occur when current pole strength (percent strength remaining) information is needed for pole loading calculations during design work per GO 95.

For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if inspections and repairs were not performed within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis and can change depending on the inspection cycle. Distribution wood pole intrusive inspections (WMP.483) can vary from year to year, as some cycles do not involve many inspections in the HFTD, and some cycles can be over 90 percent within the HFTD. Given the inspection cycle for 2023, an estimated 0.0001 ignitions would be avoided in relation to the 10-year intrusive wood pole inspection program. Calculations are shown in SDG&E Table 8-15.

SDG&E Table 8-15: Risk Reduction Methodology for Distribution Wood Pole Intrusive Inspections

Calculation Component	Component Value
Fail Rate Emergency	48%
Fail Rate Priority	4.8%
Fail Rate Non-Critical	0.40%
2023 Projected Inspection Findings Tier 3	0 + 0 + 0 = 0
2023 Projected Inspection Findings Tier 2	0 + 0 + 1 = 1
Risk events Avoided Tier 3	(0 x 48%) + (0 x 4.8%) + (0 x 0.4%) = 0
Risk events Avoided Tier 2	(0 x 48%) + (0 x 4.8%) + (1 x 0.4%) = 0.004
Distribution Ignition rate Tier 3	2.91%
Distribution Ignition rate Tier 2	2.56%
Ignitions Avoided Tier 3	0 x 2.91% = 0
Ignitions Avoided Tier 2	0.004 x 2.56% = 0.000102
Total ignitions avoided HFTD	0 + 0.000102 = 0.000102

This program was successfully completed in 2022. Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

Access issues can present challenges in performing intrusive inspections. Because intrusive inspections typically involve a minimal amount of ground disturbance around the base of the pole, authorizations to perform this work in environmentally sensitive areas can be a challenge and require added time and resources to perform. The frequency of non-routine inspections to support other WMP initiatives, such as grid hardening and asset replacement programs, can also impact routine work (reference GO 95 rule).

This program will continue in compliance with GO 165. A risk-informed approach to the performance of wood pole intrusive inspections will be evaluated to decide whether inspection cycles should be modified. SDG&E is planning to include data relative to steel poles in its risk-modeling in order to determine whether steel pole intrusive inspections should be included in our routine intrusive inspection efforts, including the frequency and scope of those steel pole inspections.

In 2022, this program was updated to remove the option of reinforcing a failed pole with less than 80 percent strength remaining in the HFTD. Instead, failed poles in the HFTD will be replaced. However, pole reinforcements that are in-flight will still be completed.

In addition, the internal audit program will be refined for distribution wood pole inspections and assessing modifications to reporting and work management through enhanced automation tools and technology. See Section 8.1.6.4 QA/QC of Transmission & Distribution Wood Pole Intrusive Inspections (WMP.1193) for additional details on the internal audit program.

8.1.3.6 Transmission Wood Pole Intrusive Inspections (WMP.1190)

GO 165 requires all wood poles over 15 years of age to be intrusively inspected within 10 years, and all poles which previously passed intrusive inspection to be inspected intrusively again on a 20-year cycle. SDG&E performs transmission wood pole intrusive inspections (WMP.1190) on an 8-year cycle.

An intrusive inspection typically involves an excavation around the pole base and/or a sound and bore of the pole at ground-line. Depending on the cavities found or the amount of rot observed, an estimate of the remaining pole strength is determined utilizing industry-wide standards. Depending on the severity of the deterioration, the pole either passes inspection, is reinforced with a steel truss, or is replaced. This replacement and reinforcement process is described in Section 8.1.7 Open Work Orders. The corrective work for replacement and reinforcement is described in Section 8.1.7 Open Work Orders. See Section 8.1.3.5 Distribution Wood Pole Intrusive Inspections (WMP.483)~~Distribution Wood Pole Intrusive Inspections (WMP.483)~~ for details on the wood pole intrusive inspection process.

Transmission Wood Pole Intrusive inspections are currently completed on an 8-year cycle, which was reduced from a 10-year cycle in 2020. Non-routine intrusive inspections may occur when current pole strength (percent strength remaining) information is needed for pole loading calculations during design.

SDG&E has a mature transmission inspection and maintenance program and participates in internal and external desktop and field audits with positive results. Industry standards and emerging technologies are also reviewed to ensure best maintenance practices are utilized.

Access issues can present challenges in performing intrusive inspections and because intrusive inspections typically involve a minimal amount of ground disturbance around the base of the pole, authorizations to perform this work in environmentally sensitive areas can be a challenge and require added time and resources to perform. The frequency of non-routine inspections to support other WMP initiatives can also impact routine work (reference GO 95).

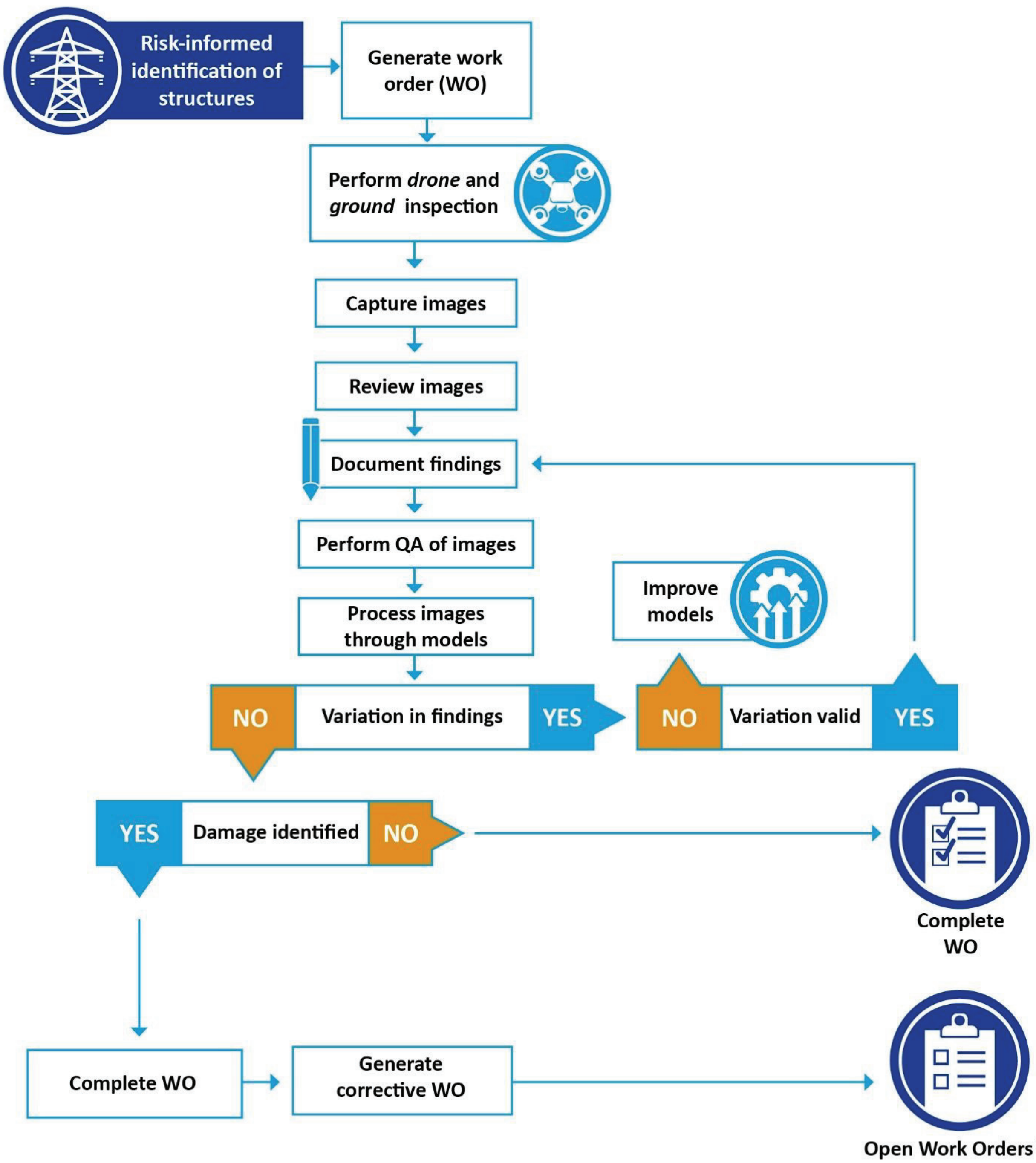
There are no plans to change the frequency of this program. However, beginning in 2025, inspections performed in the WUI will be incorporated into the WMP reporting. Additionally, some structures in the initial forecast are now steel structures that do not require an intrusive inspection, some were removed from service, and some were intrusively inspected in 2022 or 2023 and do not require an intrusive inspection in 2025.

8.1.3.7 Drone Assessments (WMP.552)

The DIAR Program (WMP.552) involves flight planning, drone flight and image capture, field observations, image assessment, determination of issues, and repair. Imagery collected by drones improves traditional ground inspections by providing inspectors with a “birds eye view” of overhead facilities, as well as high resolution imagery of overhead equipment and components. The use of drones to collect imagery enhances an inspector’s ability to identify potential fire hazards related to certain types of issues or where conditions such as terrain and vegetation density make full detailed inspections difficult. Issues that are more readily observed by the DIAR Program include damaged arresters, damaged insulators, issues with pole top work, issues with armor rods, crossarm or pole top damage, exposed connections, loose hardware, improper splices, and damaged conductors.

Images and inspection findings are also used to build damage detection models that allow IIP technology to process imagery data and improve the quality of the DIAR Program assessments. See Section 8.1.5.4.3 for more information on IIP (WMP.1342). The process for corrective work resulting from DIAR inspections is described in Section 8.1.7 Open Work Orders. Figure 8-13 outlines the process for DIAR Program assessments.

Figure 8-13: Distribution Drone Inspections Process Flow



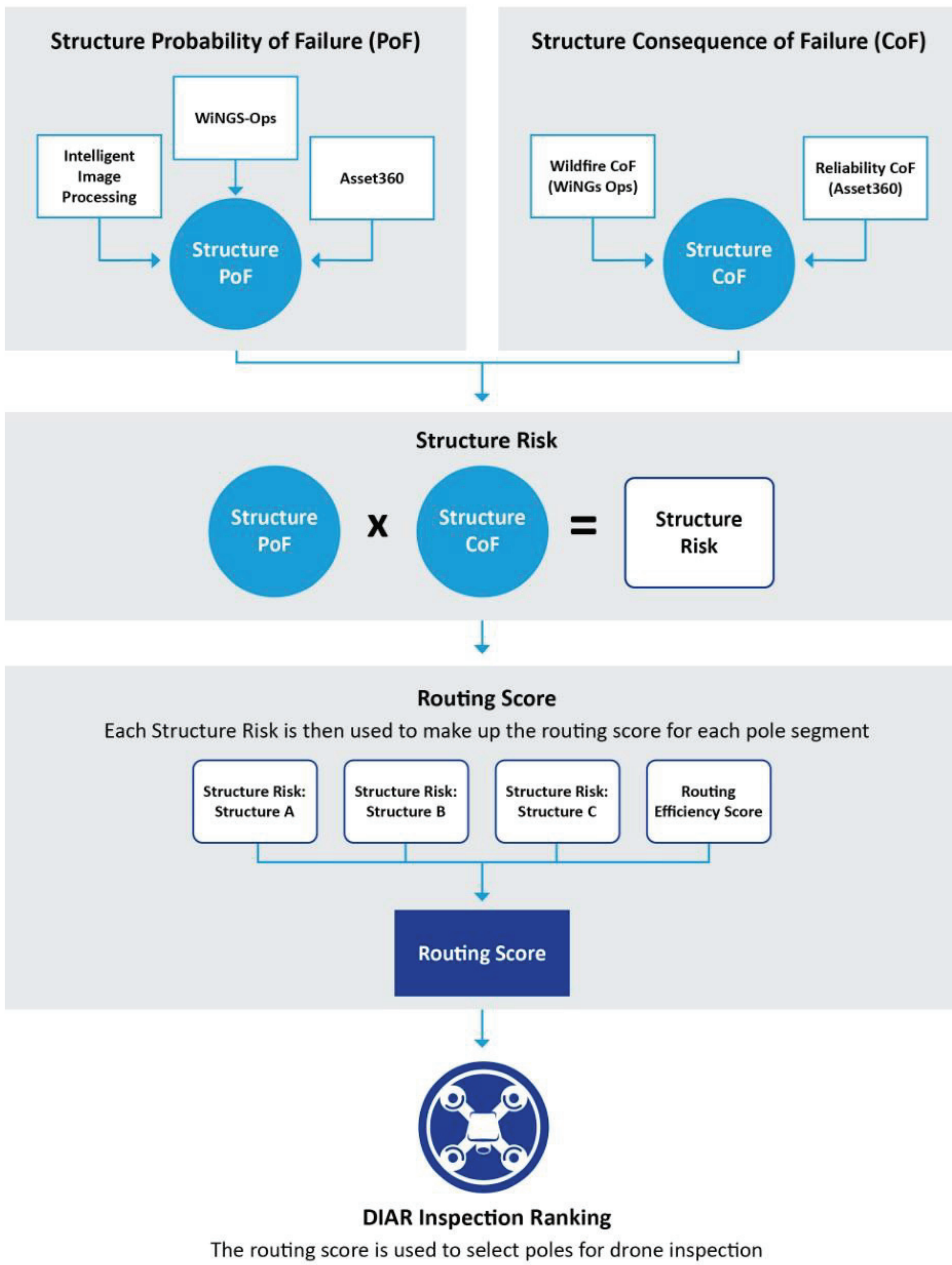
1 See Open Work Order Process Flow

The scope of the DIAR Program considers the riskiest 15 percent of overhead distribution structures within the HFTD and WUI. The structures selected for inspection are identified by using a semi-automated Inspection Prioritization Model that combines PoF and consequence of failure (CoF) to determine structure risk and account for navigation efficiency (see Figure 8-14). The model aligns with existing methods considering MAVF to identify and quantify risk and is easily modified to account for new attributes or changes in scope. This creates a repeatable and traceable process to determine the 15 percent of structures that will be assessed in a given year. Enhancements have also been made to SAP to reduce redundancy in the DIAR Program while maintaining compliance with GO 165 timelines. Accordingly, distribution structures that undergo a drone inspection will not require an overhead detailed inspection or patrol if that structure is due for a detailed inspection or patrol in the same interval.

Drone assessments of transmission infrastructure from 2020 to 2022 yielded 1 to 2 percent rates of findings. This indicates that the existing aerial inspection efforts performed on transmission infrastructure are sufficient in identifying potential issues. To optimize the use of resources and the impact to ratepayers, ad-hoc drone inspections of transmission structures for operational and reliability need will be performed. In addition, inspections of transmission components of a structure will be performed where distribution is present (i.e., where there is distribution underbuild on a transmission structure) or as part of a special inspection. For example, ad-hoc drone inspections of transmission structures may occur in the following situations:

- If a fault or failure occurs or if there is data indicating a fault or failure may occur
- Prior to or after a severe weather or safety event
- If a comprehensive ground inspection is not possible or difficult because of terrain or other access issues
- To support or supplant a climbing inspection

Figure 8-14: DIAR Inspection Prioritization Model



For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if inspections and repairs were not performed within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD Tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis, and can change depending on the inspection cycle.

For 2023, an estimated 0.3575 ignitions would occur if inspections and repairs were not completed in the prescribed timeframes as part of the DIAR Program (WMP.552). Calculations are shown in SDG&E Table 8-16.

SDG&E Table 8-16: Risk Reduction Methodology for the DIAR Program

Calculation Component	Component Value
Fail Rate Emergency	48%
Fail Rate Priority	4.8%
Fail Rate Non-Critical	0.40%
2023 Projected Inspection Findings Tier 3	8 + 120 + 671 = 799
2023 Projected Inspection Findings Tier 2	30 + 451 + 2,026 = 2,507
Risk events Avoided Tier 3	(8 x 48%) + (120 x 4.8%) + (671 x 0.4%) = 12.284
Risk events Avoided Tier 2	(30 x 48%) + (451 x 4.8%) + (2,026 x 0.4%) = 44.152
Distribution Ignition rate Tier 3	2.91%
Distribution Ignition rate Tier 2	2.56%
Ignitions Avoided Tier 3	12.284 x 2.91% = 0.3575
Ignitions Avoided Tier 2	44.152 x 2.56% = 1.130291
Total ignitions avoided HFTD	0.3575 + 1.130291 = 1.487791

From 2019 to 2022, drone inspections of all distribution poles in Tier 2 and Tier 3 of the HFTD and coastal canyon areas within the WUI were completed. Authorizations were also successfully negotiated from California State Parks to complete drone inspections for distribution poles within State Parks jurisdiction. Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

The DIAR Program has collected over 2.3 million images for over 85,000 distribution structures. Those images have enabled the development of over 96 machine learning models, including 48 asset detection models and 24 damage detection models. The accuracy of these models continues to evolve with a current average accuracy of 86 percent on the 20 damage detection models running daily. In addition, an IIP Platform (WMP.1342) was developed to not only run the machine learning models on images collected, but to store those images geospatially and support use cases for imagery from other internal departments.

The semi-automated Inspection Prioritization Model was also developed to identify the scope of the DIAR Progam in 2023 and beyond. This model supports the incoporation of the DIAR Program into traditional inspection efforts.

With the successful acquisition of authorizations to fly drones on Department of Defense and California State Parks lands, many roadblocks to the DIAR Program have been eliminated. However, there are several compliance requirements within these authorizations that require significant labor resources to maintain. This impacts the cost of implementing the program. Negative customer interactions (hostile customers) and access issues on private and Tribal land remain the primary roadblocks for inspections and resolving inspection findings.

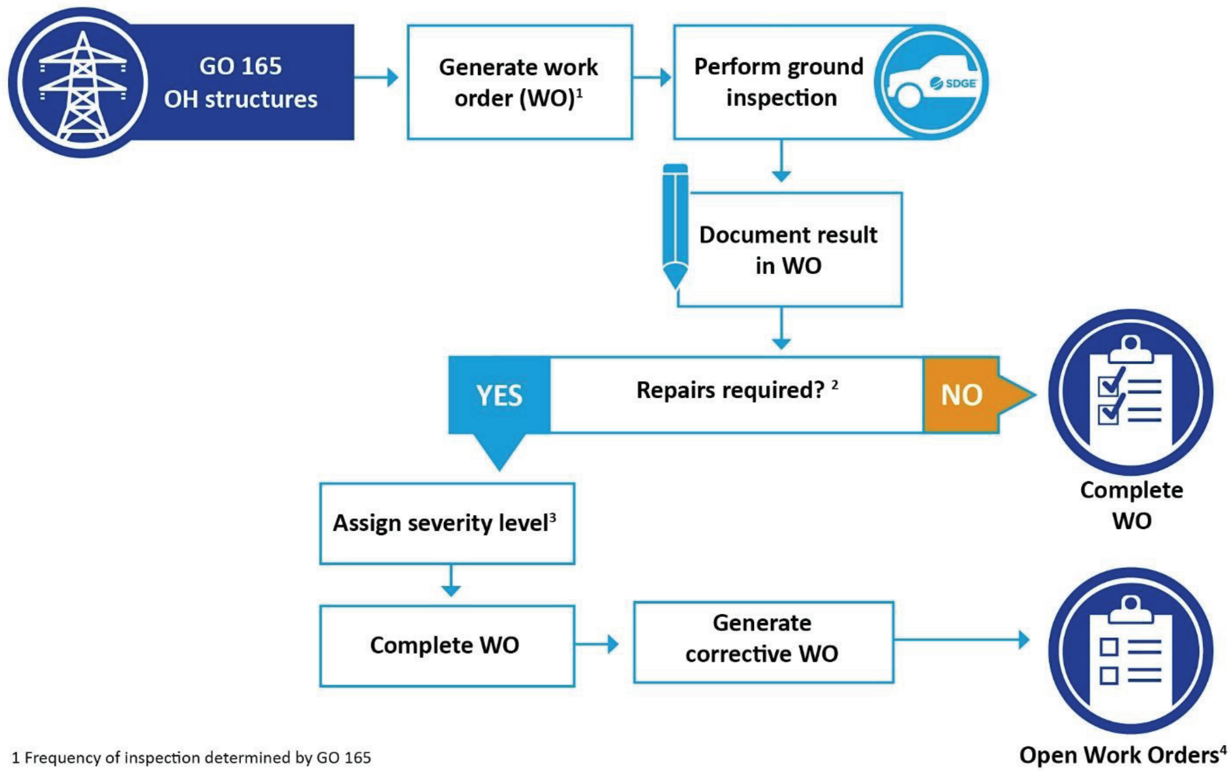
The scope of the DIAR Program has evolved since HFTD inspections were completed in 2022. For the 2023-2025 WMP cycle, the Inspection Prioritization Model will be used to determine structures to inspect in the given year. Assessment results will be utilized as a baseline to improve the Inspection Prioritization Model, which will allow inspection efforts to be better focused, and more efficient.

In addition to improving what is inspected and when, IIP models enhance the ability to process large amounts of data quickly with less dependency on human resources. More inspections of specific equipment and pole components can be performed without overburdening inspection resources. For example, images collected from mobile devices or by a fleet vehicle could identify a potential issue on an asset not scheduled for inspection in that cycle or could help detect less severe issues that would not require a repair at the time of inspection but would influence the Inspection Prioritization Model and help indicate a follow-up inspection should be conducted in a reduced timeframe.

8.1.3.8 Distribution Overhead Patrol Inspections (WMP.488)

GO 165 requires utilities to patrol their systems annually in HFTD Tier 2 and Tier 3 and in urban areas. Patrol inspections in rural areas outside of the HFTD are required once every 2 years. However, as a long-standing practice SDG&E performs patrol inspections in all areas on an annual basis. Identified issues and corrective work are tracked, demonstrating their effectiveness. The corrective work resulting from patrol inspections is described in Section 8.1.7 Open Work Orders. Figure 8-15 outlines the distribution patrol inspection process.

Figure 8-15: Distribution Patrol Inspections Process Flow



1 Frequency of inspection determined by GO 165
2 Repairs are required if work is needed to bring asset into compliance with GO
3 Severity Levels 1-3 per GO 95 Rule 18
4 See Open Work Order Process Flow

Distribution patrol inspections are currently completed on an annual basis on all structures, including those in the HFTD. Non-routine patrol inspections may occur for safety, reliability, or operational needs. For example, patrol inspections are performed on all distribution structures potentially affected by or affected by a PSPS event prior to and after the PSPS event.

Additionally, patrols are prioritized in the HFTD prior to wildfire season (defined in Appendix A).

For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level/total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. SDG&E's failure rate calculations (i.e., how many risk events would occur within a year should SDG&E not have inspected and repaired issues within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average distribution ignition rates broken down by HFTD tier were utilized to calculate ignitions avoided due to the program. The ignitions avoided is calculated on an annual basis. For 2023, an estimated 0.528 ignitions would occur should SDG&E stop completing inspections and repairs in the prescribed timeframes as part of annual distribution overhead patrol inspections (WMP.488). A summary of the calculation is provided in SDG&E Table 8-17.

SDG&E Table 8-17: Risk Reduction Estimation Methodology for Distribution Overhead Patrol Inspections

Calculation Component	Component Value
5-year average hit rate Emergency (0-3 days)	0.001
5-year average hit rate Priority (4-30 days)	0.001
5-year average hit rate Non-Critical	0.055
Fail Rate Emergency	48%
Fail Rate Priority	4.8%
Fail Rate Non-Critical	0.40%
2023 Projected Inspection Findings Tier 3	16 + 16 + 167 = 199
2023 Projected Inspection Findings Tier 2	18 + 18 + 193 = 229
Risk events Avoided Tier 3	(16 x 48%) + (16 x 4.8%) + (167 x 0.4%) = 9.116
Risk events Avoided Tier 2	(18 x 48%) + (18 x 4.8%) + (193 x 0.4%) = 10.276
Distribution Ignition rate Tier 3	2.91%
Distribution Ignition rate Tier 2	2.56%
Ignitions Avoided Tier 3	9.116 x 2.91% = 0.265
Ignitions Avoided Tier 2	10.276 x 2.56% = 0.263
Total ignitions avoided HFTD	0.265 + 0.263 = 0.528

This program was successfully completed in 2022. Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

Access issues remain the primary constraint related to the performance of patrols.

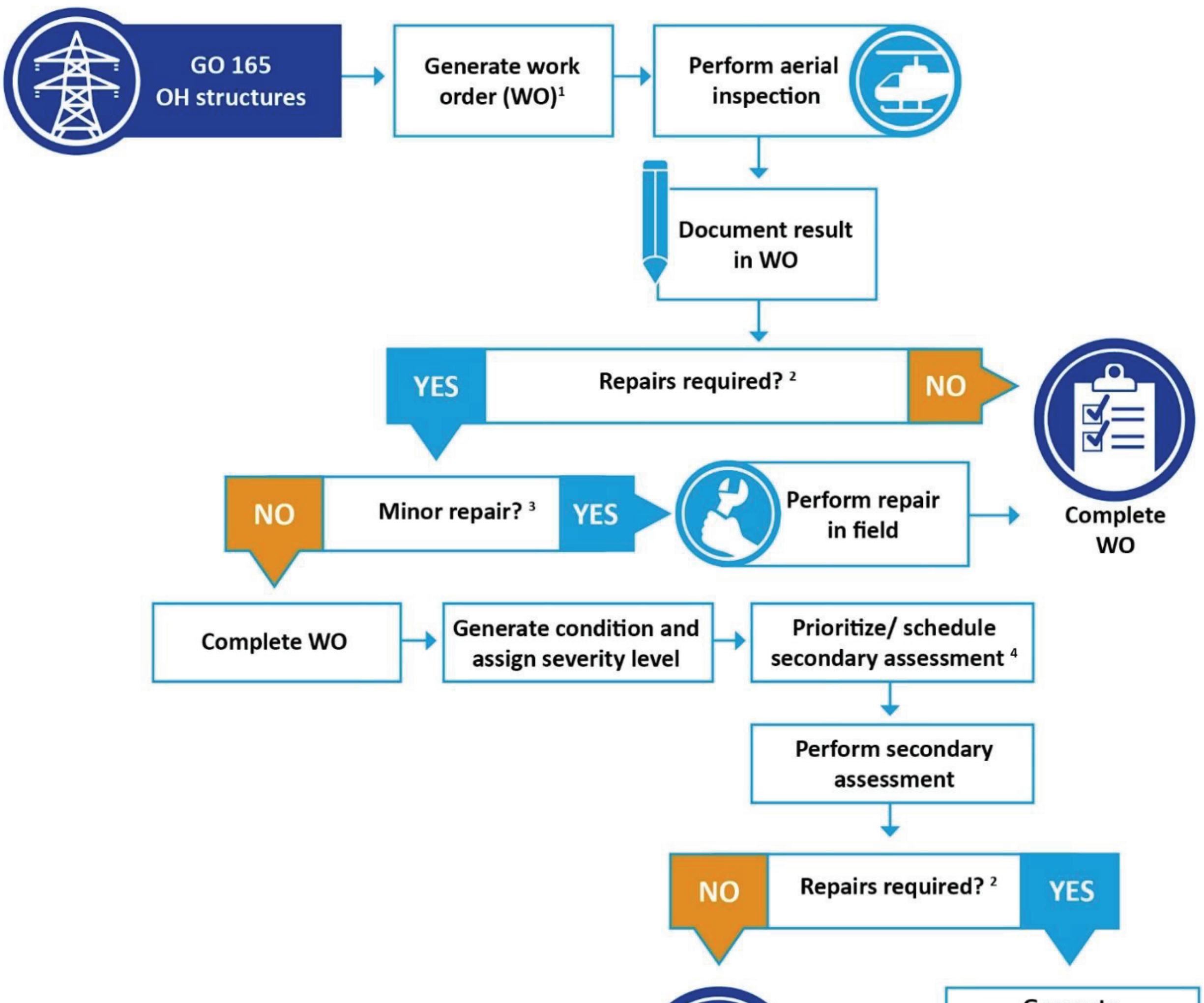
The DIAR Program (WMP.552) will continue to be administered in compliance with GO 165. In addition, patrol inspections will be enhanced by running imagery collected by drones, fleet, or mobile devices through the damage detection machine learning models to further reduce the risk of an ignition, fault, or failure event with minimal impact to inspection resources. In 2023, drone pilots will begin capturing imagery of approximately 1,000 distribution structures located within the HFTD and not scheduled for a patrol or detailed overhead visual inspection in the calendar year. Structures will be selected using the Inspection Prioritization Model. Images will run through machine learning models and images identified with a potential issue will be reviewed by a qualified inspector. If the inspector validates that the issue identified by the machine learning model is accurate and needs repair, a corrective work order will be generated (see Section 8.1.7 Open Work Orders for corrective work order process).

If this effort is successful, drone patrols using IIP (WMP.1342) will continue throughout this WMP cycle and additional imagery collected by mobile devices or fleet may be added to the scope of enhanced patrol inspections.

8.1.3.9 Transmission Overhead Patrol Inspections (WMP.489)

Transmission visual patrols are conducted annually by helicopter on all overhead tielines, including those in the HFTD. The visual patrols provide an overhead view of structures and components to identify issues such as cracked pole tops or rust/corrosion and larger issues that can pose a fire risk or risk to public safety. The corrective work resulting from patrol inspections is described in Section 8.1.7 Open Work Orders. Figure 8-16 outlines the transmission patrol inspection process (WMP.489).

Figure 8-16: Transmission Patrol Overhead Inspections Process Flow



1 Frequency of inspection determined by GO 165

2 Repairs are required if work is needed to bring asset into compliance with GO

3 Minor repair: Inspector can safely make repairs without an outage, crew, or major materials

4 See Table below

5 See Open Work Order Process Flow

Condition Severity Level	Secondary Assessment Due Date
0	Completed during initial inspection
1	Determined by inspector
2	12 months
3	6 months
4	3 months
5	Immediate

Patrols are performed annually on all tielines, including those in the HFTD. Inspections are prioritized based on the last inspection date to ensure that each tieline receives a patrol inspection within a 12-

month period. In addition, a Tier 3 patrol inspection on all 69 kV tielines is completed prior to September 1 of any given year, the beginning of wildfire season. See Section 8.1.3.10 Transmission 69 kV Tier 3 Visual Inspections (WMP.555)~~Transmission 69 kV Tier 3 Visual Inspections (WMP.555)~~ for more information on additional Tier 3 patrol inspections.

For existing programs, a 5-year historical average of hit rates (number of issues found at a given priority level/total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. SDG&E's failure rate calculations (i.e., how many risk events would occur within a year should SDG&E not have inspected and repaired issues within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average ignition rate for transmission risk events and ignitions in the HFTD was utilized to convert from risk events avoided to ignitions avoided. The ignitions avoided is calculated on an annual basis. For 2023, an estimated 0.003 ignitions are avoided as a result of transmission overhead patrol inspections (WMP.489). A summary of the calculation is provided in SDG&E Table 8-18.

SDG&E Table 8-18: Risk Reduction Methodology for Transmission Overhead Patrol Inspections

Calculation Component	Component Value
Fail Rate Emergency	48%
Fail Rate Priority	4.80%
Fail Rate Non-Critical	0.40%
2023 Projected Inspection Findings Tier 3	0 + 0 + 0 = 0
2023 Projected Inspection Findings Tier 2	0 + 1 + 0 = 1
Risk events Avoided Tier 3	(0 x 48%) + (0 x 4.8%) + (0 x 0.4%) = 0
Risk events Avoided Tier 2	(0 x 48%) + (1 x 4.8%) + (0 x 0.4%) = 0.048
Transmission Ignition rate HFTD	5.58%
Ignitions Avoided Tier 3	0 x 5.58% = 0
Ignitions Avoided Tier 2	0.048 x 5.58% = 0.003
Total ignitions avoided HFTD	0 + 0.003 = 0.003

SDG&E has a mature transmission inspection and maintenance program and participates in internal and external desktop and field audits with positive results. Industry standards, emerging technologies are also reviewed to ensure best maintenance practices are utilized. Detailed inspections were successfully completed in 2022.

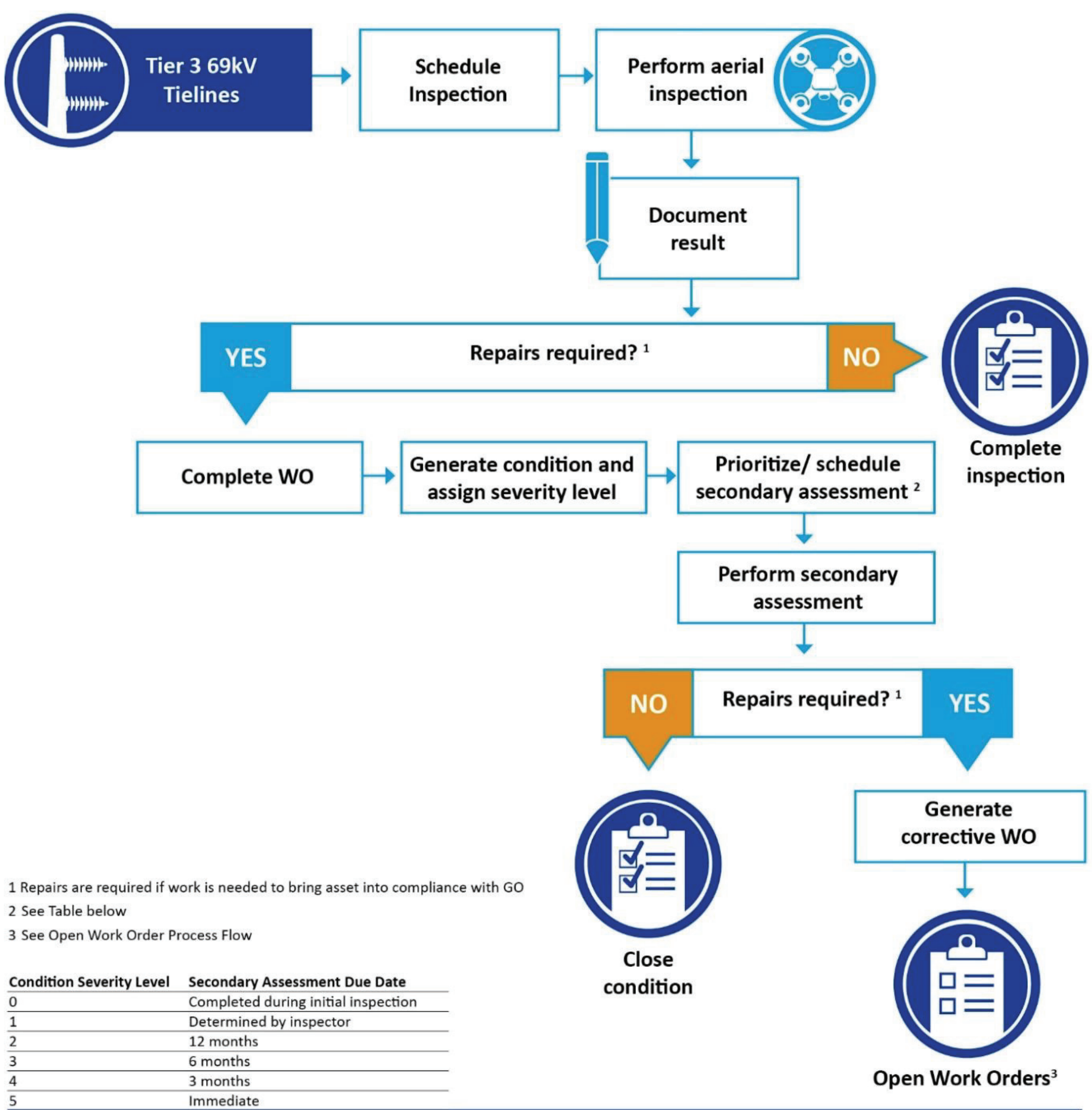
Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

There were no roadblocks encountered during 2022 and there are no plans to change the scope or frequency of this program. However, beginning in 2025, inspections performed in the WUI will be incorporated into the WMP reporting.

8.1.3.10 Transmission 69 kV Tier 3 Visual Inspections (WMP.555)

In addition to the annual visual patrol and infrared inspections (WMP.489 and WMP.482), a patrol of all 69 kV structures located in Tier 3 of the HFTD is performed prior to September 1 each year. Similar to the yearly inspection, these inspections are designed to identify obvious structure problems and hazards prior to fire season. The corrective work resulting from these visual inspections is described in Section 8.1.7 Open Work Orders. Figure 8-17 outlines the process for these additional patrols.

Figure 8-17: Transmission Tier 3 69 kV Inspections Process Flow



Condition Severity Level	Secondary Assessment Due Date
0	Completed during initial inspection
1	Determined by inspector
2	12 months
3	6 months
4	3 months
5	Immediate

69 kV Tier 3 inspections are currently performed on an annual basis and completed prior to September 1 of each year.

For existing programs, a 5-year historical average of "hit rates" (number of issues found at a given priority level divided by total inspections) was calculated and utilized to forecast future years based on the number of inspections in the HFTD for these programs. Failure rate calculations (i.e., how many risk events would occur within a year if inspections and repairs were not performed within the prescribed timeframes) were utilized to convert issues found into risk events. Finally, the average ignition rate for transmission risk events and ignitions in the HFTD was utilized to convert from risk events avoided to ignitions avoided. The ignitions avoided is calculated on an annual basis. For 2023, an estimated 0.00 ignitions would occur if inspections and repairs are not performed in the prescribed timeframes as part of transmission 69 kV Tier 3 visual inspections (WMP.555). Calculations are shown in SDG&E Table 8-19.

SDG&E Table 8-19: Risk Reduction Estimation for Transmission 69 kV Tier 3 Visual Inspections

Calculation Component	Component Value
Fail Rate Emergency	48%
Fail Rate Priority	4.80%
Fail Rate Non-Critical	0.40%
2023 Projected Inspection Findings Tier 3	0 + 1 + 0 = 1
2023 Projected Inspection Findings Tier 2	0 + 0 + 0 = 0
Risk events Avoided Tier 3	(0 x 48%) + (1 x 4.8%) + (0 x 0.4%) = 0.048
Risk events Avoided Tier 2	(0 x 48%) + (0 x 4.8%) + (0 x 0.4%) = 0
Transmission Ignition rate HFTD	5.58%
Ignitions Avoided Tier 3	0.048 x 5.58% = 0.002678
Ignitions Avoided Tier 2	0 x 5.58% = 0
Total ignitions avoided HFTD	0.002678 + 0 = 0.002678

SDG&E has a mature transmission inspection and maintenance program and participates in internal and external desktop and field audits with positive results. Industry standards and emerging technologies are also reviewed to ensure best maintenance practices are utilized. Detailed inspections were successfully completed in 2022.

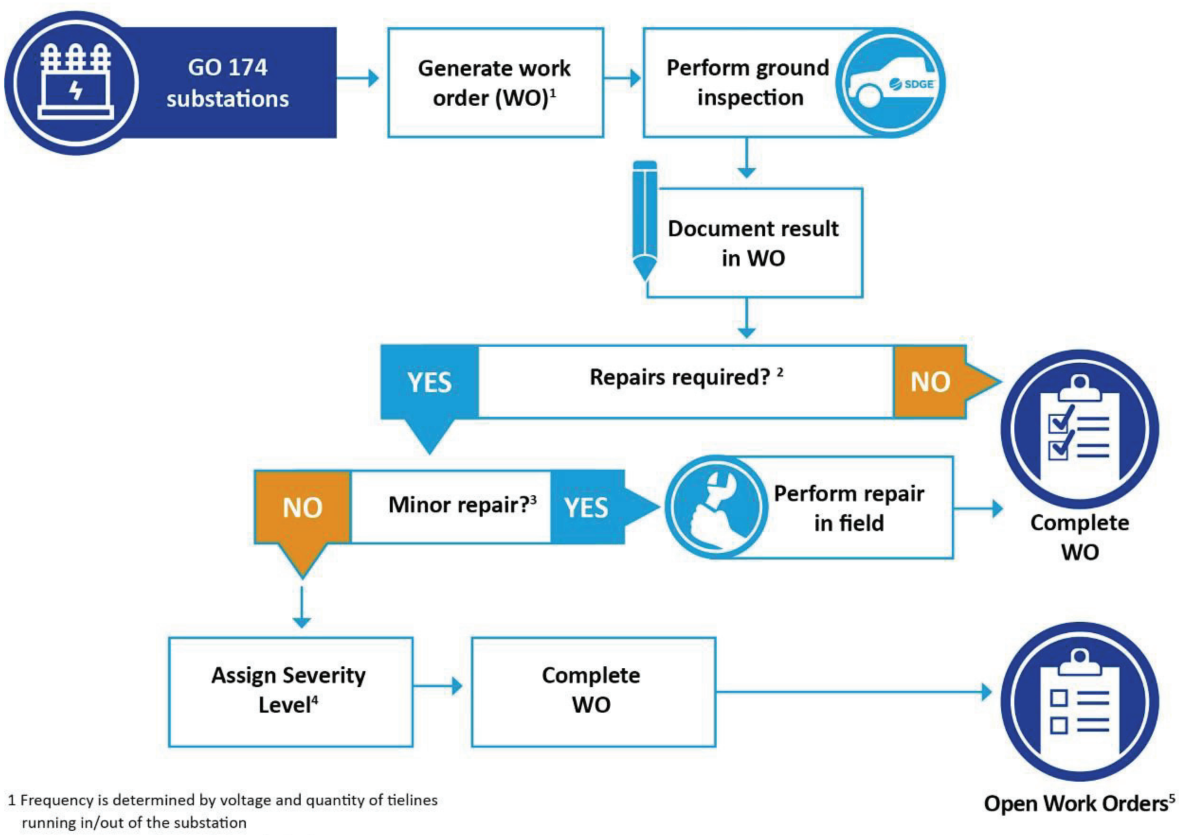
Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

There were no roadblocks encountered during 2022 and there are no plans to change the scope or frequency of this program.

8.1.3.11 Substation Patrol Inspections (WMP.492)

The Substation Inspection and Maintenance Program (WMP.492) identifies substation equipment deterioration to make repairs or replacements before a failure occurs, as mandated by GO 174. The program is conducted primarily for reliability; however, it also provides incidental wildfire mitigation benefits within the HFTD and the WUI. The Substation Inspection and Maintenance Program schedules routine inspections at recurring cycles. These inspections consist of a monthly or bimonthly patrol inspection where equipment is inspected and problems, such as oil leaks, are identified. When issues are identified during an inspection, corrective work orders are opened with a severity level of either immediate (within 7 days) or within the next 12 months. While patrol inspections primarily focus on substation assets, switchyard vegetation hazards are also identified and corrective maintenance is addressed. The corrective work for substation patrol inspections is described in Section 8.1.7 Open Work Orders. Figure 8-18 outlines the substation patrol inspection process.

Figure 8-18: Substation Patrol Inspection Workflow



1 Frequency is determined by voltage and quantity of tielines running in/out of the substation
2 Repairs are required if work is needed to bring asset into compliance with GO or SDG&E standards
3 Minor repair: Inspector can safely make repairs without an outage, crew, or major materials
4 See Table
5 See Open Work Order Process Flow

Substation Severity Levels and Corrective Action Timeframe

Severity Code Level	Corrective Action Due Date
Security Code 1	7 days
Security Code 2	12 months

Substation Patrol Inspections are currently performed on a monthly or bi-monthly basis depending on certain criteria. Priority 1 substations have an operating voltage above 200 kV or have four or more transmission lines at or above 69 kV. These substations are patrolled monthly. All other substations are categorized as Priority 2 and are patrolled once every 2 months.

This program was successfully completed in 2022. Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics, respectively.

A system enhancement is currently being implemented to autogenerate corrective maintenance orders for frequently identified findings during patrol inspections. SDG&E Table 8-20 shows findings that will result in an autogenerated corrective maintenance order.

SDG&E Table 8-20: Findings that Trigger Autogenerated Corrective Maintenance Order

Finding	Description of finding
Vegetation Overgrowth	Heavy or hazardous overgrowth
Fence Repair	Fence height less than 7 feet minimum, or fence grounds are cut or vandalized
Breather Desiccant	Desiccant indicates expiration in LTC transformers
Petro Pipes	Switchyard and LTC Transformer containment pits

Autogenerating corrective maintenance orders has resulted in a high volume of Breather Desiccant alerts. This appears to be due to the recent implementation of a new desiccant color. The unusually high volume is being investigated and additional training will be provided to the inspectors for desiccant review. This issue does not impact SDG&E's ability to complete timely inspections.

In 2022, an internal periodic review of substation patrol inspections was implemented. Results of this internal review will inform future updates to the program and revisions to inspector training and procedures as needed. See Section 8.1.6.5 QA/QC of Substation Inspections (WMP.1194) for more information on periodic reviews.

8.1.3.12 Discontinued Asset Inspection Programs

8.1.3.12.1 LiDAR Inspections of Distribution Electric Lines and Equipment

In 2022, all circuits within the HFTD had LiDAR data captured and processed. LiDAR data was used to perform vegetation risk analysis on selected circuits within the HFTD. Because the entire HFTD was captured, a large-scale LiDAR collection initiative will not be implemented again for several years. However, LiDAR will continue to be captured to support pole loading calculations needed for system hardening projects such as covered conductor and traditional overhead hardening and corrective work orders involving pole or crossarm replacements. LiDAR is needed to complete PLS-CADD during pre-construction and post-construction to verify compliance with GO 95 and SDG&E standards and specifications. See Section 8.1.2.1 and Section 8.1.2.5 for more information on covered conductor and traditional overhead hardening, respectively (WMP.455, WMP.543).

Performance metrics for 2022 are provided in Section 8.1.1.3.

8.1.3.12.2 HFTD Tier 3 Distribution Pole Inspections

Additional HFTD Tier 3 distribution pole inspections were conducted from 2010 through 2016 as a result of a settlement agreement adopted in D.10-04-047. In 2017, SDG&E decided to proactively continue the HFTD Tier 3 Quality Assessment/Quality Control (QA/QC, WMP.193) inspections as part of its regular inspection program. However, in an effort to implement risk-informed inspections, SDG&E is discontinuing the HFTD Tier 3 QA/QC inspections in its current form and replacing it with risk-informed drone inspections described in Section 8.1.3.7 Drone Assessments (WMP.552). There are no plans to change the frequency of this program. However, beginning in 2025, inspections performed in the WUI will be incorporated in the WMP reporting. This change focuses on risk reduction by increasing the potential scope of inspections to the entire HFTD and coastal canyons within the WUI rather than only HFTD Tier 3.

This program was successfully completed in 2022, and performance metrics for 2022 are provided in 8.1.1.3.

8.1.4 Equipment Maintenance and Repair (WMP.1130)

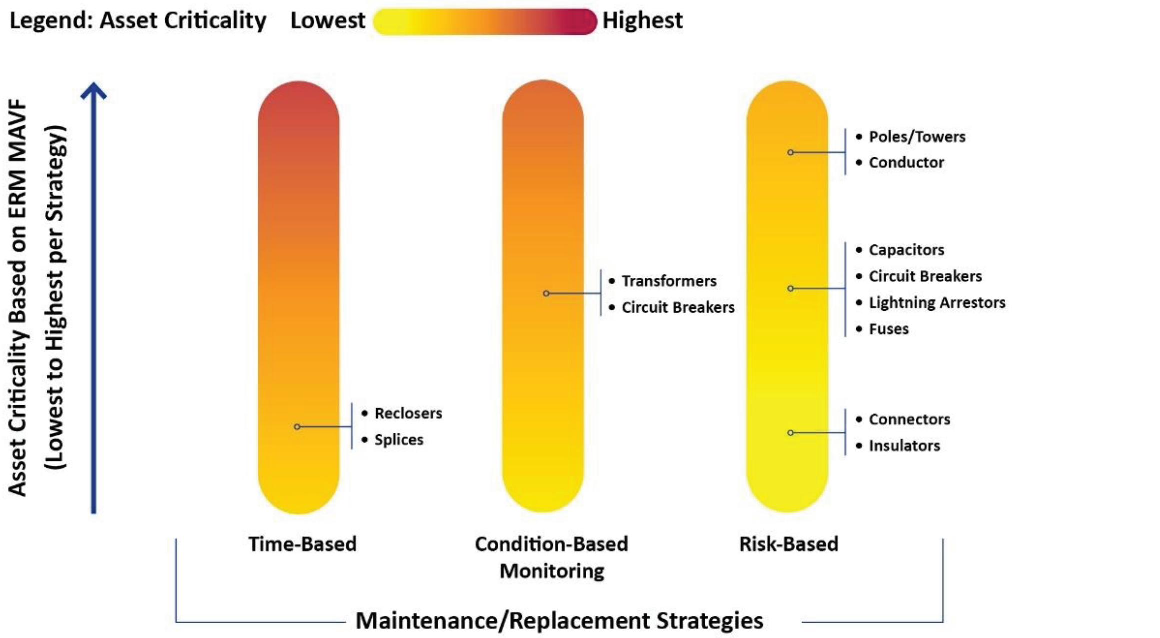
8.1.4.1 Maintenance, Repair, and Replacement Strategies

SDG&E operates within a Safety Management System (SMS) founded on a proactive, risk-informed, data-driven approach to effectively manage risk and safety. SMS is a systematic, enterprise-wide cohesive framework to collectively manage and reduce risk and exposure and promote continuous improvement in safety performance through deliberate, routine, and intentional processes. SMS processes include the identification, prevention, control, and mitigation of potential safety incidents (e.g., fire, asset failure, injury). Having the necessary asset maintenance and testing procedures help mitigate the risk of an asset failure or safety incident.

Asset maintenance and replacement strategies vary by equipment type and are determined based on asset criticality. Figure 8-19 summarizes the strategies that are utilized for each equipment type based on asset criticality. These replacement strategies promote public safety and meet or exceed regulatory mandates and industry best practices. At a minimum, all equipment is maintained with a time-based inspection cycle (see Section 8.1.3 Asset Inspections).

Maintenance and replacement of assets beyond what is required by regulation is determined based on asset condition and risk when such information is available. The Asset 360 platform (WMP.1341) was created to enable development of asset health indices, equipment failure analysis, and predictive risk modeling. Such analysis can result in the need for a proactive maintenance or replacement strategy. Some examples include grid hardening initiatives (see Section 8.1.2 Grid Design and System Hardening), replacing fiber-wrapped poles where the fiber wrap is end of life, transmission lattice tower hardening, and polymer insulator replacements. See Section 8.1.5.4.2 for details on Asset 360.

Figure 8-19: Asset Criticality and Maintenance/Replacement Strategies



SDG&E Table 8-21defines current maintenance and replacement strategies by equipment type and identifies specific programs and initiatives.

SDG&E Table 8-21: Maintenance and Replacement Strategies

Maintenance/Replacement Strategy	Definition	Equipment Type	WMP Initiative (or other)
Reactive	This strategy is utilized to maintain/replace an asset or equipment when an asset or equipment is operated until it stops functioning per its specifications. This is a reactionary strategy since the asset is only replaced when it fails. It is used for lower risk assets that do not impact public safety.	All equipment, when needed	Asset Inspections WMP.478; WMP.479; WMP.481; WMP.482; WMP.483; WMP.1190; WMP.488; WMP.489; WMP.555; WMP.492
Time-based (Interval-based)	This strategy is utilized to maintain/replace an asset or equipment that does not meet acceptance criteria found during a routine, cyclical inspection. The inspection cycle may be determined by regulatory mandates, equipment manufacturer recommendation, or industry best practice.	All equipment as required	Asset Inspections WMP.478; WMP.479; WMP.481; WMP.482; WMP.483; WMP.1190; WMP.488; WMP.489; WMP.555; WMP.492
Condition-based Monitoring	This strategy is utilized to maintain/replace an asset or equipment when certain attributes of the asset or equipment exceed the defined thresholds as alerted by a continuous monitoring system. This strategy requires continuous monitoring and analysis	Substation transformers and circuit breakers	Other Substation CBM program WMP.492

Maintenance/Replacement Strategy	Definition	Equipment Type	WMP Initiative (or other)
	of key health data of an asset such as age, location, gassing, number of operations, electrical loading, and temperature.		
Risk-based	This strategy is utilized to maintain/replace an asset or equipment based on the probability and consequence of failure. While the automated condition-based strategy considers the health of the asset, which is often a proxy for the likelihood of failure, the risk-based strategy considers the consequence of failure of the assets in addition to the health of the asset.	Poles/Towers Conductor Capacitors Lightning Arresters Fuses Connectors Insulators	Grid Hardening Initiatives WMP.453; WMP.459; WMP.464; WMP.550 Risk-based inspections WMP.481; WMP.552

8.1.4.2 Impact of Inspection Programs

A study was performed to measure the effectiveness of repair timeframes at preventing equipment failures. Results of the study also provided baseline data for the estimation of the effectiveness of inspection programs at preventing risk events and ignitions.

The methodology for the study was as follows:

1. Five years of reliability data and corrective maintenance data were queried.
2. The reliability data set was filtered into risk events.
3. The data set was further filtered to look at equipment failures only which are the primary target of the CMP.
4. CMP data was queried to identify all infractions associated with structures and when those infractions were repaired.
5. To and from fields of the risk data set were used to identify structures that had risk events associated with structures that had pending corrective maintenance infractions.

The results of the study show that the CMP and repair timeframes are effective at preventing equipment failures (see SDG&E Table 8-22). For the purpose of estimating the effectiveness of inspections, the 0.40 percent rate of infractions that led to failures is used to forecast priority and emergency fail rate. This failure rate will be scaled up with severity of inspection findings.

SDG&E Table 8-22: Risk Event Rate with Pending Infractions

	5-Year Total	Annual Average
Risk events with pending infractions	8	2
Total equipment risk events	2,009	402
Risk event rate with pending infractions	0.40%	0.40%

8.1.4.3 SCADA Capacitors Maintenance and Replacement Program (WMP.453)

8.1.4.3.1 Utility Initiative Tracking ID

WMP.453

8.1.4.3.2 Overview of the Activity

Current capacitors are designed to provide continuous voltage and power factor correction for the distribution system. During a failure of a capacitor from either mechanical, electrical, or environmental overstress, an internal fault is created resulting in internal pressure and the potential to rupture the casing. This rupture of molten metal has the potential to be an ignition source. Capacitor faults are currently protected through fusing, which is not always effective at preventing this high-risk failure from becoming an ignition source.

The SCADA Capacitors Maintenance and Replacement Program (WMP.453) was developed to replace existing non-SCADA capacitors with a more modern SCADA-switchable capacitor or to remove non-SCADA capacitors if not required for voltage or reactive support. These modernized capacitors have a monitoring system to check for imbalances and isolate internal faults before they become catastrophic. SCADA capacitors also have the capacity for remote isolation and monitoring of the system which provides additional situational awareness during extreme weather conditions. The SCADA Capacitors Maintenance and Replacement Program prioritizes replacing or removing fixed capacitors from service and then addresses capacitors with switches. Both types of capacitors will be modernized to a SCADA switchable capacitor. While this program will not reduce capacitor faults, the advanced protection equipment is designed to detect and isolate issues before a capacitor rupture occurs, reducing the failure mode most likely to lead to an ignition.

8.1.4.3.3 Impact of the Activity on Wildfire Risk

The SCADA Capacitors Maintenance and Replacement Program (WMP.453) will detect and isolate issues before a capacitor rupture occurs, reducing the failure mode most likely to lead to an ignition. It is estimated that the SCADA Capacitors Maintenance and Replacement Program will reduce Capacitor Caused HFTD ignitions by 0.0006 by 2025. Calculations are shown in SDG&E Table 8-23.

SDG&E Table 8-23: Risk Reduction Estimation for SCADA Capacitors

Calculation Component	Component Value
Risk Events Tier 3 (average 2017-2021)	0.2
Risk Events Tier2 (average 2017-2021)	1
Risk Events Non-HFTD (average 2017-2021)	9.2
Average Ignition Rate Tier 3	0.0291
Average Ignition Rate Tier 2	0.0256
Average Ignition Rate Non-HFTD	0.0113
Effectiveness Estimate	0.8
Ignition Reduction Estimate Tier 3	0.2 x 2.91% x 80% = 0.004656
Ignition Reduction Estimate Tier 2	1 x 2.55% x 80% = 0.0204
Ignition Reduction Estimate Non-HFTD	9.2 x 1.13% x 80% = 0.083168

Calculation Component	Component Value
Capacitors in Tier 3	37
Capacitors in Tier 2	69
Capacitors in the Non-HFTD	597
Capacitors in the Tier 3 HFTD (2023-2025)	0
Capacitors in the Tier 2 HFTD (2023-2025)	2
Capacitors in the Non-HFTD (2023-2025)	13
Ignitions reduced Tier 3 HFTD	0.004656 x (0 ÷ 37) = 0
Ignitions reduced Tier 2 HFTD	0.0204 x (2 ÷ 69) = 0.0006
Ignitions reduced non-HFTD	0.083168 x (13 ÷ 597) = 0.0018
Ignitions reduced	0 + 0.0006 + 0.0018= 0.0024

8.1.4.3.4 Impact of the Activity on PSPS Risk

The purpose of the SCADA Capacitors Maintenance and Replacement Program (WMP.453) is to reduce the risk of wildfire. This program does not affect the PSPS risk.

8.1.4.3.5 Updates to the Activity

In 2022, the SCADA Capacitors Maintenance and Replacement Program (WMP.453) expanded to the WUI. These are areas within a 2-mile buffer outside the HFTD whose surrounding areas make them prone to fire ignition.

8.1.4.4 Expulsion Fuse Replacement Program (WMP.459)

8.1.4.4.1 Utility Initiative Tracking ID

WMP.459

8.1.4.4.2 Overview of the Activity

When the distribution system experiences a fault or overcurrent, there are fuses connected to the system to protect its integrity and isolate the fault. These expulsion fuses are designed to operate by creating a significant expulsion within the fuse, resulting in the fuse opening and isolating the fault, and in turn limiting further damage to other equipment. Because of this internal expulsion, the fuses are equipped with a venting system that sends a discharge of energy out of the fuse and into the atmosphere. This external discharge has the potential to ignite flammable vegetation.

The Expulsion Fuse Replacement Program (WMP.459) replaces existing expulsion fuses with new, more fire safe expulsion fuses that are approved by CAL FIRE. These new expulsion fuses reduce the discharge expelled into the atmosphere, reducing the chance of a fuse operation leading to an ignition.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

8.1.4.4.3 Impact of the Activity on Wildfire Risk

Over the 2023 to 2025 WMP cycle, mitigation done by the Expulsion Fuse Replacement Program (WMP.459) is expected to reduce ignitions by 0.6735 annually. Based on preliminary study results, work done by the program to install CAL FIRE-approved fuses is 100 percent effective at reducing ignition risk. Because SDG&E plans to complete this mitigation, replacing all expulsion fuses within the HFTD by 2025, it is estimated that the risk of ignitions from this cause will be mitigated. Calculations are shown in SDG&E Table 8-24.

SDG&E Table 8-24: Risk Reduction Estimation for the Expulsion Fuse Replacement Program

Calculation Component	Component Value
Expulsion Fuse Operation Tier 3 (5-year average)	83.6
Expulsion Fuse Operation Tier 2 (5-year average)	85.8
Average ignition rate Tier 3	2.91%
Average ignition rate Tier 2	2.56%
Pre mitigation ignitions Tier 3	83.6 x 2.91% = 2.433
Pre mitigation ignitions Tier 2	85.8 x 2.56% = 2.1965
Number of fuses installed Tier 3 (2023-2025)	1,573
Number of fuses installed Tier 2 (2023-2025)	6,483
Fuses to be replaced Tier 3	350
Fuses to be replaced Tier 2	390
Ignition Reduced Tier 3	(350 ÷ 1,573) x 2.433 = 0.5414
Ignition Reduced Tier 2	(390 ÷ 6,483) x 2.1965 = 0.1321
Ignition Reduction HFTD	0.5415 + 0.1321 = 0.6735

8.1.4.4.4 Impact of the Activity on PSPS Risk

The purpose of the Expulsion Fuse Replacement Program (WMP.459) is to reduce the risk of wildfire. This program does not affect the PSPS risk.

8.1.4.4.5 Updates to the Activity

The Expulsion Fuse Replacement Program (WMP.459) is expected to be completed in December of 2025.

An efficacy study was done to test the ignition rate of new CAL FIRE-approved fuses with traditional expulsion fuses: CAL FIRE-Approved Expulsion Fuses vs Other Expulsion Fuses.

The following methodology was followed:

1. The GIS database was utilized to identify the locations and installation dates of new CAL FIRE-approved fuses.
2. Risk event data from 2015 through 2021 was reviewed to identify all risk events isolated by overhead fuses, including counting separate events when multiple fuses operated (more than single phase) and if, during testing, the fuse operated.

3. The risk event isolating device structure and the risk event date was compared to the GIS database to determine if the risk event was isolated by a non-CAL FIRE-approved expulsion fuse or a CAL FIRE-approved expulsion fuse.
4. Fuse operation data was compared to the ignition database data to determine which fuse operations had led to an ignition.

When CAL FIRE-approved fuses were used, there was a reduction in ignition rate percentage from 0.12 percent to 0 percent (see SDG&E Table 8-25). SDG&E Table 8-26 shows fuse operation and ignition rate reduction by HFTD Tier. Currently, there are not enough samples for the data to show a statistically significant reduction, however, the early results are promising.

SDG&E Table 8-25: CAL FIRE and Expulsion Fuse Operation 2015-2021

Fuse Type	Fuse Operation	Number of Ignitions	Ignition Rate
CAL FIRE-Approved Fuse	760	0	0%
Expulsion Fuse	2,477	3	0.12%

SDG&E Table 8-26: CAL FIRE and Expulsion Fuse Operation 2015-2021 by HFTD Tier

Fuse Type	Area	Fuse Operation	Number of Ignitions	Ignition Rate
CAL FIRE	Non-HFTD	334	0	0%
CAL FIRE	Tier 2	199	0	0%
CAL FIRE	Tier 3	228	0	0%
Expulsion	Non-HFTD	1,455	2	0.14%
Expulsion	Tier 2	484	0	0%
Expulsion	Tier 3	474	1	0.21%

8.1.4.5 Hotline Clamp Replacement Program (WMP.464)

8.1.4.5.1 Utility Initiative Tracking ID

WMP.464

8.1.4.5.2 Overview of the Activity

Connectors that have been connected directly to overhead primary conductors, known as hotline clamps (HLCs), are associated with creating a weak connection which could result in a wire down event. This in turn could lead to an energized wire either coming into contact with the ground or a foreign object where it could become a source of ignition.

The HLC Replacement Program (WMP.464) replaces HLC connections that are connected directly to overhead primary conductors with compression, wedge, or other approved connections to eliminate the risk of wire-down failure and the associated ignition risk. HLC connections will be installed concurrently with other asset replacement initiatives across the HFTD such as avian protection (WMP.972), fuse replacements, and lightning arrester replacements (WMP.550).

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

8.1.4.5.3 Impact of the Activity on Wildfire Risk

The replacement of HLCs reduces the risk of connection failures that could lead to an energized wire-down event. Data was gathered from historical wire downs associated with connection failures, ignition percentages within the HFTD, and the number of replacements expected by the end of 2025. Ignitions are expected to be reduced by 0.0265 ignitions per year over the 2023-2025 WMP cycle. Calculations are shown in SDG&E Table 8-27.

SDG&E Table 8-27: Risk Reduction Estimation for the HLC Program

Calculation Component	Component Value
Tier 2 wire downs (2017-2021 average for connector failures)	3
Tier 3 wire downs (2017-2021 average for connector failures)	2.75
Non HFTD wire downs 2017-2021 average for connector failures)	4
Ignition rate Tier 2 (2017-2021 average)	2.56%
Ignition rate Tier 3 (2017-2021 average)	2.91%
Ignition rate Non HFTD (2017-2021 average)	1.13%
Mitigation Effectiveness	90.00%
Estimated Ignition Reduction Tier 2	90% x 3 x 2.56% = 0.06887
Estimated Ignition Reduction Tier 3	90% x 2.75 x 2.91% = 0.07197
Estimated Ignition Reduction Non HFTD	90% x 4 x 1.13% = 0.04083
Total Hotline Clamps in the network Tier 2	5,426
Total Hotline Clamps in the network Tier 3	3,094
Total Hotline Clamps in the network Non HFTD	7,264
Hotline clamps replaced (2023-2025) Tier 2	553
Hotline clamps replaced (2023-2025) Tier 3	672
Hotline clamps replaced (2023-2025) Non HFTD	225
Ignition Reduced Tier 2	(553 ÷ 5,426) x 0.06887 = 0.0078
Ignition Reduced Tier 3	(672 ÷ 3,094) x 0.07197 = 0.0174
Ignition Reduced Non HFTD	(225 ÷ 7,264) x 0.04083 = 0.0013
Total Ignition Reduced	0.0078 + 0.0174 + 0.0013 = 0.0265

8.1.4.5.4 Impact of the Activity on PSPS Risk

The purpose of the HLC Replacement Program (WMP.464) is to reduce the risk of wildfire. This program does not affect the PSPS risk.

8.1.4.5.5 Updates to the Activity

The HLC Replacement Program (WMP.464) is expected to continue in 2025.

Changes in the 2025 HLC replacement target resulted from fielding assessments performed in tandem with Lightning Arrestor Removal and Replacement (WMP.550), Avian Protection (WMP.972), and Expulsion Fuse Replacement (WMP.459) fielding. Fielding assessments performed in 2023 resulted in a significant number of structures in the HFTD and WUI that require HLC replacement.

8.1.4.6 Lightning Arrester Removal and Replacement (WMP.550)

8.1.4.6.1 Utility Initiative Tracking ID

WMP.550

8.1.4.6.2 Overview of the Activity

Lightning arresters are pieces of electrical equipment designed to mitigate the impact of transient overvoltage on the electric system. If the overvoltage duration is too long or too high, the arrester can become thermally overloaded, causing these units to fail in a way where they can become an ignition source.

The Lightning Arresters Replacement Program (WMP.550) installs CAL FIRE-approved lightning arresters to mitigate the impact of transient overvoltage on the electric system. CAL FIRE-approved lightning arresters are equipped with an external device that operates prior to the arrester overloading, dramatically reducing the potential of becoming an ignition source.

Targets for 2023 and performance metrics for 2022 are provided in Section 8.1.1.2 Targets and Section 8.1.1.3 Performance Metrics respectively.

8.1.4.6.3 Impact of the Activity on Wildfire Risk

The ignitions reduced by 2025 was calculated using the 5-year average risk events caused by lightning arresters, the 5-year average ignitions caused by lightning arresters, the assumed effectiveness of 80 percent, and the number of planned lightning arrester installations for the 3-year WMP cycle. The mitigation will have an estimated 80 percent reduction in ignitions based on the technology and what the product is designed to accomplish. Based on this data, an ignition reduction of 0.134 and 0.029 in Tier 3 and Tier 2, respectively, are expected between 2023 and 2025. Calculations are shown in SDG&E Table 8-28.

SDG&E Table 8-28: Risk Reduction Estimation for Lightning Arrester Program

Calculation Component	Component Value
Pre-mitigation ignitions Tier 3 (5-year average)	0.8
Pre-mitigation ignitions Tier 2 (5-year average)	0.4
Pre-mitigation ignitions Non HFTD (5-year average)	0
Effectiveness	80%
Ignitions reduced Tier 3	0.8 x 80% = 0.640
Ignitions reduced Tier 2	0.4 x 80% = 0.320
Ignitions reduced Non HFTD	0 x 80% = 0
Total Arresters Tier 3	17,766
Total Arresters Tier 2	16,440

Calculation Component	Component Value
Total Arresters Non HFTD	33,237
Arresters Tier 3 (2023-2025)	3,708
Arresters Tier 2 (2023-2025)	1,500
Arresters Non HFTD (2023-2025)	336
Ignitions reduced Tier 3	0.64 x (3,708 ÷ 17,766) = 0.134
Ignitions reduced Tier 2	0.32 x (1,500 ÷ 16,440) = 0.029
Ignitions reduced Non HFTD	0 x (336 ÷33237) = 0
Total ignition reduction	0.134 + 0.029 + 0 = 0.163

8.1.4.6.4 Impact of the Activity on PSPS Risk

The purpose of the Lightning Arresters Replacement Program (WMP.550) is to reduce the risk of wildfire. This program does not affect the PSPS risk.

8.1.4.6.5 Updates to the Activity

There were no updates to the Lightning Arresters Replacement Program (WMP.550) in 2022.

8.1.5 Asset Management and Inspection Enterprise System(s)

8.1.5.1 Distribution Systems (WMP.1332)

Systems Applications and Processes Plant Maintenance (SAP PM) stores distribution master asset records, including the inspection and maintenance records for the CMP.

SAP PM is a collection of standard and custom tables. Standard SAP tables are documented by the vendor. Custom tables are documented in the technical design documents for a particular project, which includes the data dictionary and taxonomy for the project scope. SAP PM technical documentation is grouped by project and stored on a SharePoint site for each project.

SAP PM data is stored on SDG&E servers on an SAP Hana database. Any attachments to SAP records are stored on SAP content server.

SAP PM is integrated with a GIS mapping system used to capture, edit, analyze, manage, and display spatial or geographic data. The scope of the asset information documented in GIS includes distribution, transmission, substation, telecommunication, and land assets. The system tracks equipment location, unique equipment attributes, and circuit information. Click Mobile on Mobile Data Terminals (MDTs) is used to collect detailed CMP inspection data. Epoch Mobile on MDTs is used to collect inspection data from the Wood Pole Intrusive inspections (WMP.1190 and WMP.483).

SAP PM is also integrated with Asset 360 (WMP.1341). See Section 8.1.5.4.2 for more detailed information.

The distribution inspection data in SAP PM is used to create the audit sample and track results and any related corrective actions. See Section 8.1.6 for more detailed information on the QA/QC program (WMP.491).

SAP PM changes are managed in the Change Request Management (CHARM) system. System updates are moved between environments (from Development to QA to Production). System Investigation Report (SIR) methodology is used to manage the changes.

Drone inspection (WMP.552) notifications/work orders will be captured in SAP PM. The planned completion date for this action is the end of 2023. Drone inspection findings will also be captured in SAP PM with a planned completion date of 2024.

The use of Click Mobile will be transitioning to GeoCall for Field Service Management starting in 2023 with CMP inspections. CMP inspection data will be collected using GeoCall using iOS devices and MDTs.

8.1.5.2 Transmission Systems

Transmission Construction and Maintenance (TCM) Data is used to track inspection findings and record maintenance work completed as a result of inspections.

Integration between TCM Data, PowerWorkz, CityWorks, and Epoch Mobile are documented in high-level data flow diagrams. CityWorks standard tables are documented by the vendor.

TCM Data is stored in a Structured Query Language (SQL) database on SDG&E servers. CityWorks and PowerWorkz are stored in an Oracle database on an SDG&E server.

TCM is updated with GIS mapping system information which is used to capture, edit, analyze, manage, and display spatial or geographic data. The scope of the asset information documented in GIS includes distribution, transmission, substation, telecommunication, and land assets. The system tracks equipment location, unique equipment attributes, and circuit information.

CityWorks is an application used to schedule work orders for transmission asset inspections. Epoch Mobile application on MDTs is used to collect field inspection data. PowerWorkz is the mobile synchronization database used to make data updates between Epoch Mobile and CityWorks. Extracts from PowerWorkz are manually imported into TCM Data to update new conditions from inspections completed.

TCM Data is integrated also with Asset 360 (WMP.1341). See Section 8.1.5.4.2 for more detailed information.

TCM Data is used to track inspection findings and record maintenance work completed as a result of inspections. A secondary assessment, or internal audit, is performed on 100 percent of findings identified and results are captured in TCM Data. See Section 8.1.6 for more detailed information on QA/QC (WMP.1191).

If TCM database format changes are made, the TCM data analysts are updated via direct email communication or meetings.

For CityWorks and PowerWorkz changes, change requests are managed through the standard IT Change management methodology using an SIR. Issues are managed through a ServiceNow ticketing system. A Change Advisory Board (CAB) reviews proposed changes each week.

There are plans to replace the legacy TCM Data system with an enterprise asset management system. Implementation for this project is yet to be determined, however it is included in the 10-year objectives for asset inspections (see Section 8.1.3.2 Transmission Overhead Detailed Inspections (WMP.479)).

There were no significant changes to TCM Data policies, processes, or controls since the last WMP submission.

8.1.5.3 Substation Systems

The Substation Maintenance Management System, known as Cascade, is the system of record for substation asset master records and is used for work management of assets inside the substation including asset attributes, maintenance triggers, history of maintenance completed, and equipment failures. Cascade is an off-the-shelf system supported by a vendor, DNV.

Documentation of the Cascade system includes system architecture diagrams, database diagrams, and a user guide.

Cascade is a SQL database stored on SDG&E servers. Data collection field units run on a SYBASE database.

SORT is used to dispatch substation alarm investigations and various types of substation inspections. SORT dispatches are reported in Cascade as a work order. Substation Condition Based Maintenance (CBM) is used for real-time monitoring of equipment (such as infrared inspections), management of notifications, and damage risk assessments. See Section 8.1.4 Equipment Maintenance and Repair for more information on CBM.

The substation inspection data in Cascade is used to create the audit sample and track results and any related corrective actions. See Section 8.1.6 for more detailed information on the QA/QC program (WMP.1194).

Changes made to the Cascade system follow the IT project lifecycle methodology. Minor changes (e.g., new fields, workflow, configurations) are made by Business Analysts. Major changes are made by DNV. Change (enhancement) requests, including functional requirements and project signoffs, are stored on a SharePoint site. Business users are responsible for updating Standard Operating Procedures (SOPs) and related training.

In the next year, there are no planned changes to policies, processes, or controls.

In 2022, Cascade was upgraded from version 3.5 to version 3.8. This upgrade allowed for performance improvements, higher security, and enhanced usability. This upgrade also included a database migration from Sybase to a SeQuel database.

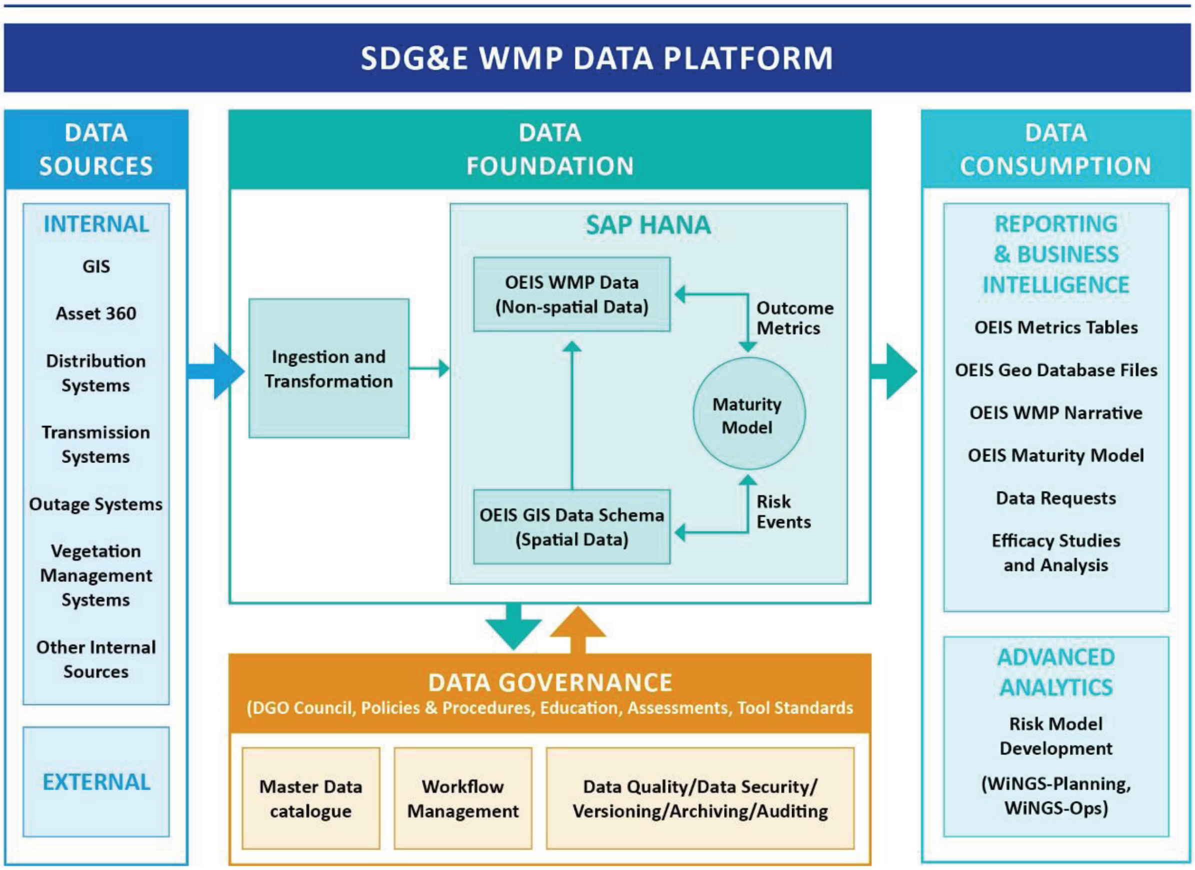
8.1.5.4 Integrated Asset Management Systems (WMP.1332)

8.1.5.4.1 WMP Data Platform (WMP.519)

The WMP data platform provides a centralized data lake that enables consistent, reliable and automated reporting of the spatial and non-spatial Quarterly Data Report (QDR) mandated by the OEIS.

Data is ingested into the data foundation from multiple data sources including asset systems, asset inspection systems, outage systems, vegetation management systems, and other internal and external systems enabling one source of truth for data consumption. Data consumption includes regulatory reporting, internal reporting, efficacy studies, and advanced analytics. The data platform is governed by management oversight, policies and procedures, education, and tool standards. An overview of the WMP Data Platform is in Figure 8-20.

Figure 8-20: WMP Data Platform



8.1.5.4.2 Asset 360 (WMP.1341)

Asset Management utilizes data as the fulcrum to enable improved risk-informed decision making. It is critical to unify disparate data from across the enterprise into a consumable and curated fashion. Curated asset data is now embedded into risk models and business processes throughout the Company to improve decision making. For example, in the past, age was typically used as a proxy for asset health. Although age plays a factor in asset health, a risk-based approach that considers robust asset data from inspections, failures, outages, and the surrounding environment needs to be considered. Through the Asset 360 program, a per-asset health score is created for critical assets to better assess an asset's performance, health, and the impact when assets fail.

The Asset 360 program ingests data from imagery, other risk models, and external data sources to improve model accuracy and performance. Integrating results of image-based analytics including IIP (WMP.1342) will help improve asset predictive models in the future. Data quality has begun to be measured and improvement efforts to remediate data in the source systems has also begun. Partnerships have been established between Asset Management, Enterprise Risk Management, Wildfire Mitigation Program, and the source system teams to continuously improve data quality. Starting this year, tools to further automate the data quality issue identification and remediation process will be evaluated and eventually adopted. The integration of asset data and the development of asset health predictive models will formulate an assessment of asset risk, which can be utilized by operating and engineering teams to develop and analyze their projects, programs, and/or initiatives, improving risk-based decision making.

To date, Asset 360 has created asset conditions for the following:

- Distribution Primary overhead Conductor
- Distribution Wood Poles
- Distribution overhead Switches (Hook Stick, Gang Operated, Reclosers)
- Distribution underground Switches (Oil-filled switches, fault interrupters)
- Distribution underground Tees
- Distribution underground Cable
- Distribution overhead capacitors

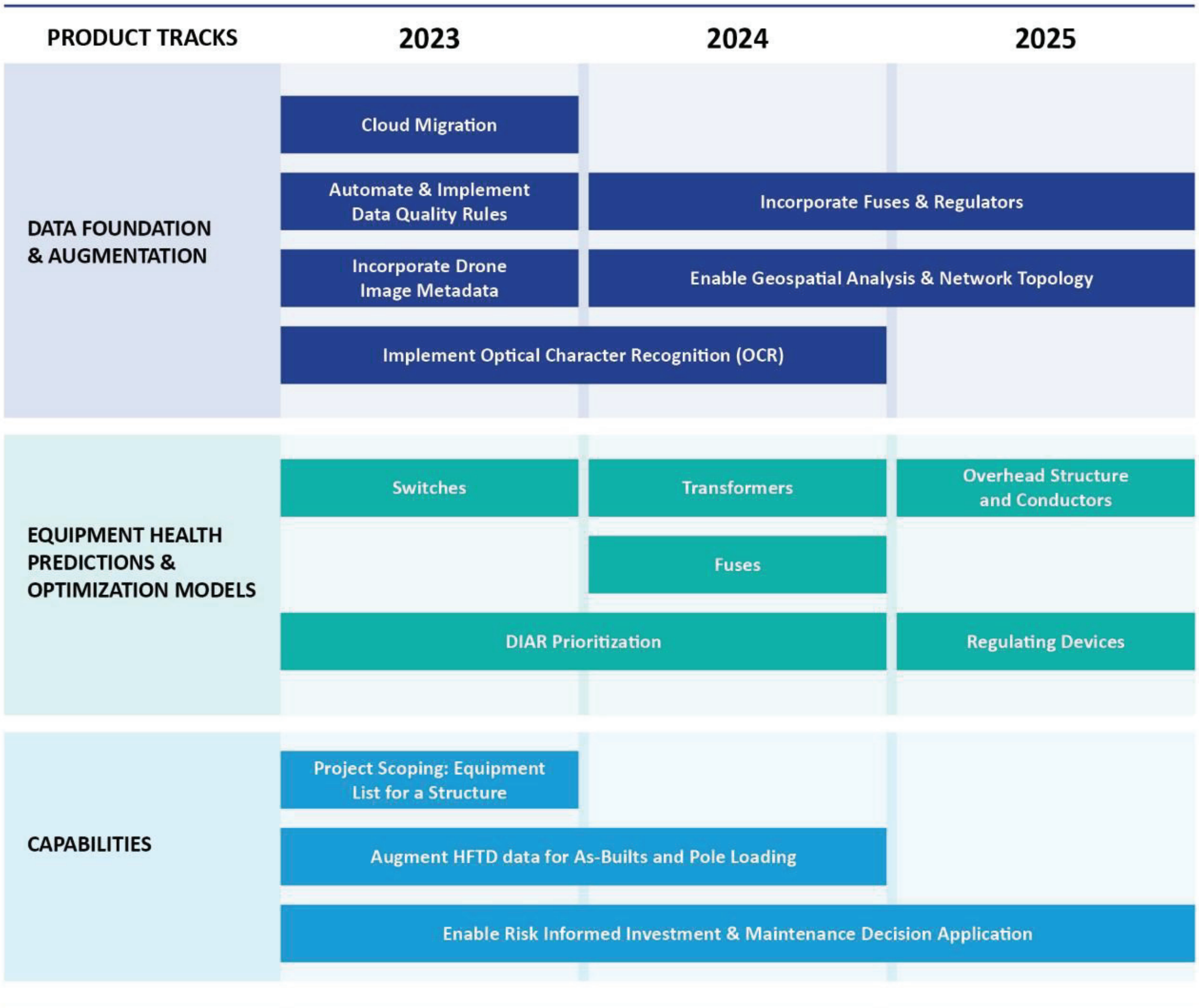
Asset 360 has also created risk indices for the following assets:

- Distribution Primary overhead Conductor
- Distribution Wood Poles
- Distribution overhead Switches (Oil-filled switches, fault interrupters)
- Distribution underground Tees
- Distribution underground Cable

In 2023, Asset 360 will continue to improve existing models for asset condition and risk as well as incorporate new assets into the platform including potheads, secondary, and transformers.

Asset 360 data is automatically integrated with distribution and transmission source systems. See Figure 8-21 for a roadmap of planned changes and improvements to Asset 360.

Figure 8-21: Asset 360 3-Year Roadmap



8.1.5.4.3 Intelligent Image Processing (WMP.1342)

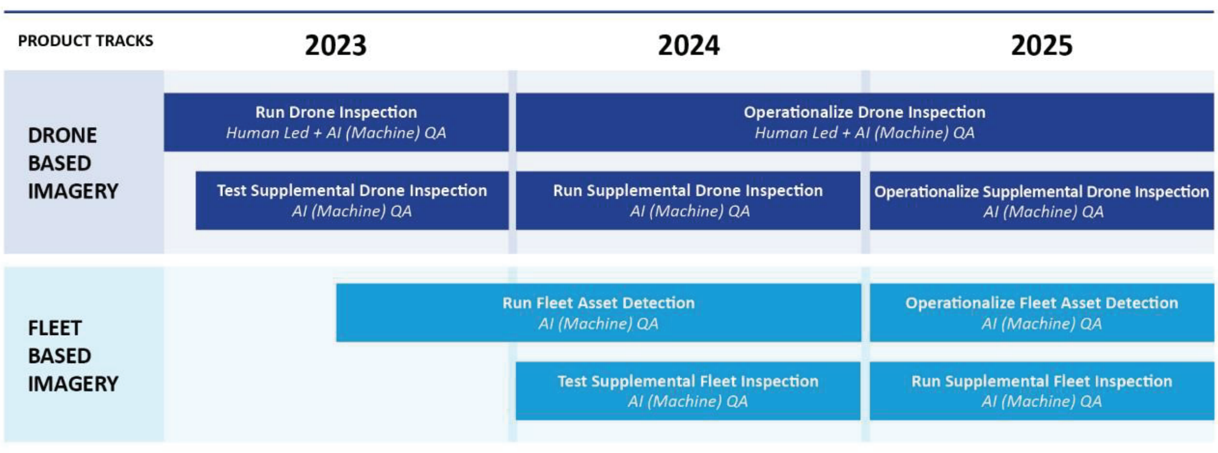
IIP (WMP.1342) is an image capture, enterprise image repository, and Artificial Intelligence (AI) and ML processing engine. In 2021, IIP harnessed digital capabilities to accelerate AI and ML, cutting-edge data acquisition technologies, and human/machine workflows to support wildfire mitigation and compliance activities. IIP collects, retains, and analyzes images from various acquisitions to enable damage detection and risk analysis for distribution. Acquisitions include, but are not limited to, drone, mobile, LiDAR, and Fleet captures in the HFTD and WUI areas. In 2022, IIP operationalized these digital capabilities utilizing the 4 million images in image repository and AI and ML to:

- To date analyzed over 850,000 images (39,000 poles) in HFTD for fire risks utilizing AI damage detection models in support of the DIAR Program (WMP.552)
- Analyzed over 2 million images (75,000 poles) in HFTD for fire risks utilizing AI asset detection models in support of WMP asset replacement programs

- Analyzed over 2 million images in HFTD for Communication Infrastructure Provider (CIP) presence, third party Attacher, utilizing AI third-party Attacher equipment detection models in support of Pole Attachment Compliance program
- Ingested and stored in enterprise image repository LiDAR files and data for 205 circuits utilized as part of the 2022 HFTD LiDAR data capture.

Over this WMP cycle, IIP technology will continue to improve the quality of inspections through enhancement to its damage detection models and expanded utilization within drone inspection efforts (see Section 8.1.3.7 Drone Assessments (WMP.552)). There are no plans to change the frequency of this program. However, beginning in 2025, inspections performed in the WUI will be incorporated into the WMP reporting. As discussed in Section 8.1.5.4.2, IIP will continue enhancement of asset identification models to support improvements to the Asset inventory that helps improved risk-informed decision making. LiDAR imagery ingested and stored in IIP will be used to inventory overhead secondary wire and services in the HFTD Tier 3 region. IIP data is automatically integrated with overhead distribution and transmission source systems. See Figure 8-22 for a roadmap of planned changes and improvements to IIP.

Figure 8-22: IIP 3-Year Roadmap



8.1.6 Quality Assurance and Quality Control

OEIS Table 8-7: Grid Design and Maintenance QA/QC Program

Inspection Program being audited	Audit Program Name	Procedure/ Program Documenting QA/QC Activities	Auditor Qualifications**	Sample Size	Type of Audit	2022 Audit Results	Yearly Target Pass Rate (2023-2025)
All Transmission Inspection Programs	QA/QC of Transmission Inspections (WMP.1191)	Internal Transmission Line Maintenance Practice*	Construction Supervisor	100% of conditions identified during inspection	Field and Desktop	n/a	See 10-year Objectives

Inspection Program being audited	Audit Program Name	Procedure/ Program Documenting QA/QC Activities	Auditor Qualifications**	Sample Size	Type of Audit	2022 Audit Results	Yearly Target Pass Rate (2023-2025)
Distribution Overhead Detailed Inspections (WMP.478)	QA/QC of Distribution Detailed Inspections (WMP.491)	ESP 612	Construction Supervisor	50% of conditions identified during inspection	Field	100%	100%
Distribution Drone Assessments (WMP.552)	QA/QC of Distribution Drone Assessments (WMP.1192)	DIAR SOP, Data Capture and Assessment Manual	Construction Supervisor	100%	Desktop	100%	100%
Distribution & Transmission Wood Pole Intrusive Inspections (WMP.483 and WMP.1190)	QA/QC of Wood Pole Intrusive Inspections (WMP.1193)	Wood Pole Inspection Audit Procedures	Third party contractor - auditor	10%	Field	88%	88%
Substation Patrol Inspections (WMP.492)	QA/QC of Substation Inspections (WMP.1194)	SOP 510.040	Construction Supervisor	~18 annually	Field	100%	90%

**Contains confidential and sensitive information*
***Personnel qualified to conduct audits in these program areas have the title listed in the table. Additional information on the qualifications for each title can be found in Section 8.1.9.*

8.1.6.1 QA/QC of Transmission Inspections (WMP.1191)

QA/QC of transmission inspections is also referred to as secondary assessments for conditions identified during inspection. The process for these secondary assessments is outlined in SDG&E's internal transmission line maintenance practices for the purpose validating inspection results. A construction supervisor performs a field assessment for 100 percent of conditions identified during an inspection. Secondary assessments are prioritized based on severity level of the condition and on HFTD region. The construction supervisor will validate whether the condition identified during inspection is valid or if no further maintenance is required. See Section 8.1.3 Asset Inspections for detailed processes for transmission secondary assessments and Section 8.1.9 Workforce Planning for qualifications of the construction supervisor.

Discrepancies and lessons learned as a result of secondary assessments are addressed and resolved in real time during staff meetings.

There are no plans to change the scope or frequency of this program.

8.1.6.2 QA/QC of Distribution Detailed Inspections (WMP.491)

QA/QC of distribution detailed inspections (WMP.478) is managed by Operations and Engineering managers. Beginning in 2025, the program will be enhanced by having supervisors assess 50% of findings identified during inspection within 1 month of the inspection and documenting the results of those assessments. In addition, 5% of inspections will be audited by quality control personnel via field visits and desktop review of images collected within 1 month of the completed inspection. These enhancements will track pass/fail audit results, which will be communicated back to inspectors. Trends will be monitored and appropriate training will be delivered either individually or through annual refresher trainings administered to all qualified inspectors.

8.1.6.3 QA/QC of Distribution Drone Assessments (WMP.1192)

QA/QC of distribution drone assessments (WMP.552) is performed by Construction Supervisors reviewing 100 percent of assessments and images processed through the machine learning models in production. If any discrepancies are identified, the Construction Supervisor will provide feedback to the Inspector during regular team meetings and the inspection findings will be updated prior to finalization. Similarly, if there are any variations between the results of the machine learning model findings and the Inspector's findings, that information will be reviewed and validated by the Construction Supervisor. Information will be sent back to the Construction Supervisor and the missed issues will be included in the inspection findings prior to finalization. Lessons learned, as well as updates to inspection requirements are also incorporated into initial and refresher training materials. There have been no changes to the QA/QC process since the last WMP submission. See Section 8.1.9 Workforce Planning for qualifications of workers.

8.1.6.4 QA/QC of Transmission & Distribution Wood Pole Intrusive Inspections (WMP.1193)

The audit program for wood pole intrusive inspections (WMP.483 and WMP.1190) is outlined in an internal wood pole inspection audit procedure. This program targets 10 percent of completed inspections to audit monthly and utilizes a randomizer to select the structures. This sample size is determined based on feasibility of performing the audits on a monthly basis. A third party is contracted to perform a field audit of the 10 percent of completed inspections for both distribution and transmission structures. Third party auditors are required to successfully pass two weeks of auditor training that is conducted by the third party. The audit field verifies the initial inspection results monthly. Audit findings are recorded in the wood pole inspection management system and shared with program administrators. Results are reviewed and shared at routine monthly meetings with the intrusive inspectors and their leadership. Work is reissued to intrusive inspectors when discrepancies are identified, and corrections are performed within 2 weeks of the finding. Trending discrepancies are identified and addressed with root cause and field visits.

In 2022, enhancements were developed to move from a manual process of selecting the audit sample population to a more efficient, automated randomizer selection tool within the wood pole inspection management system.

8.1.6.5 QA/QC of Substation Inspections (WMP.1194)

QA/QC of substation inspections (WMP.492) is performed as outlined in SDG&E's *510.040 Substation Inspector Maintenance Order Reporting and Tracking*. Completed substation patrol inspections are periodically reviewed by a Construction Supervisor for quality control of regulatory requirements, relevancy, and internal considerations. The sample size for periodic review is determined by the number of substation inspectors performing patrol inspections. Per 510.040, the periodic review consists of 10 inspections, at different substations, for each inspector per 6-month period. Currently, three inspectors are utilized to perform substation patrol inspections, which results in 60 reviews annually (approximately 5 percent of completed patrol inspections), of which approximately 30 percent are performed in the HFTD. The Construction Supervisor documents the completion of the review and any noted deficiencies in a maintenance order for the relevant substation. The documentation includes the route, date, substation name, inspector name, and a checklist of items reviewed. The deficiencies are noted on a form that resides in the maintenance order. Should any discrepancies be found, the Construction Supervisor will conduct a near real-time training with all inspectors including an example of the deficiency followed by a display of the correct course of action. See Section 8.1.9 Workforce Planning for qualifications of the substation construction supervisor.

This periodic review is a new program implemented in 2022. Enhancements to the system of record for substation patrol inspections have been implemented to support this program. A yearly target pass rate of 90 percent has been established; however, results of the periodic review has yet to inform any changes or enhancements to the inspection program or training procedures.

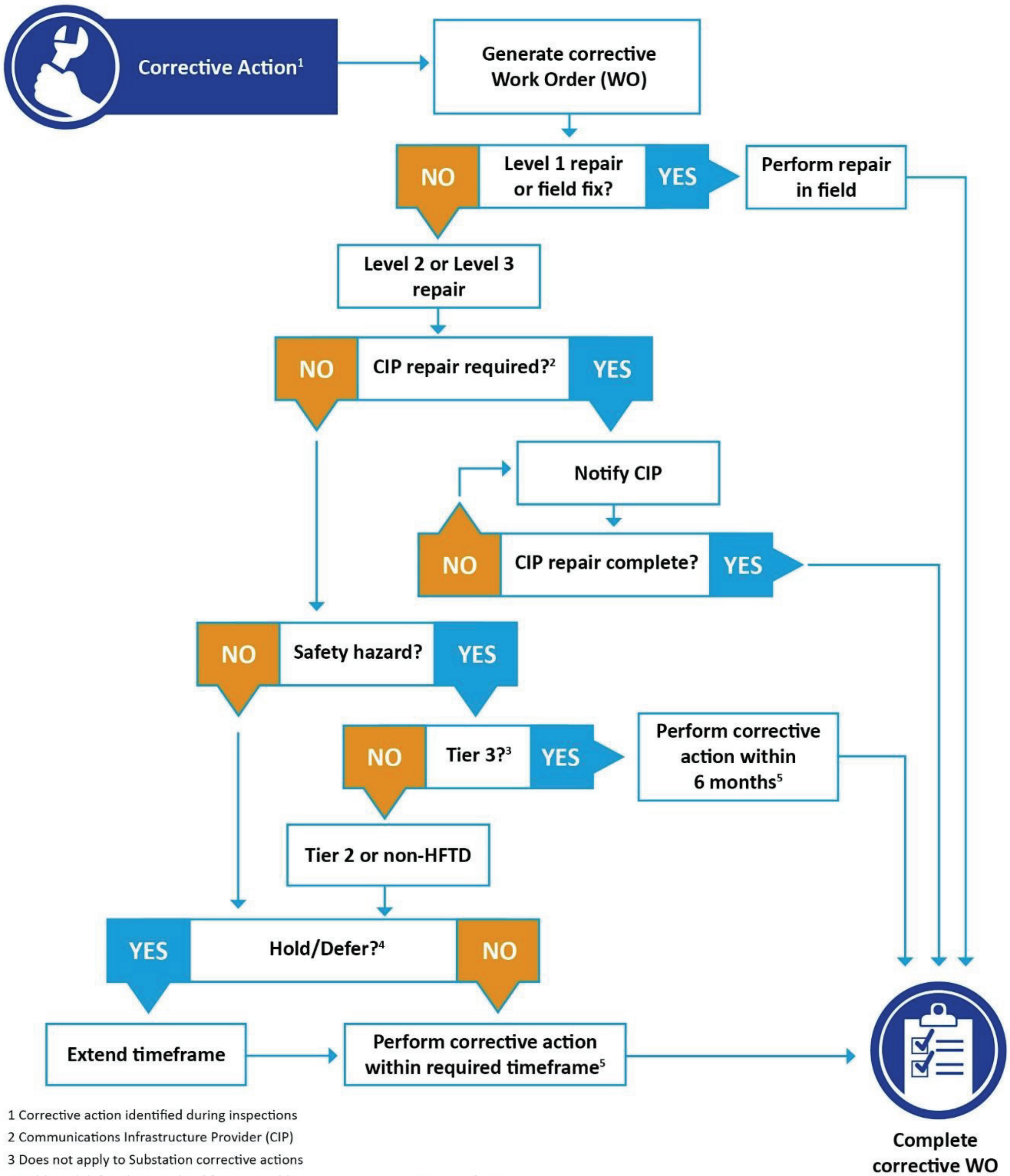
8.1.7 Open Work Orders (WMP.1065)

8.1.7.1 Procedures/Programs Documenting the Work Order Process

The CMP programs for transmission and distribution assets define the requirements for corrective maintenance. Corrective maintenance is managed through initiation, prioritization, and completion of corrective work orders. SDG&E adheres to all GO regulations for addressing corrective maintenance within required timeframes and, when applicable, will exceed requirements based on severity level and region prioritization. See Section 8.1.3 Asset Inspections for more details on asset inspection programs and procedures describing corrective work order processes associated with each inspection program.

Figure 8-23 outlines the process for addressing corrective work orders resulting from inspections.

Figure 8-23: Open Work Orders: Corrective Maintenance



1 Corrective action identified during inspections
2 Communications Infrastructure Provider (CIP)
3 Does not apply to Substation corrective actions
4 Holds and deferrals are utilized for reasonable circumstances per GO 95 and 174
5. See Table below

GO 95 Rule 18 Corrective Action Timeframe

	Level 1	Level 2	Level 3
Non-HFTD	≤ 30 days	12 months	12 months
Tier 2	≤ 30 days	12 months	12 months
Tier 3	≤ 30 days	6 months	12 months

8.1.7.2 Prioritization of Work Orders

Corrective work orders are assigned a severity level, which determines the timeframe for making the repair or replacing the asset per GO 95. Region prioritization such as HFTD is also a factor in determining timeframe for work order completion. Level 1 findings are addressed immediately in the field when the situation is made safe to do so. Minor repairs that do not require engineering design, a crew, an outage, or additional materials can also be addressed on site immediately. Level 2 and 3 repairs are evaluated based on safety and addressed accordingly. See Figure 8-23 for specific severity levels and timeframes for repair.

8.1.7.3 Plan for Eliminating a Backlog of Work Orders, if Applicable

Deferred work in the HFTD is primarily related to permitting delays and access issues. SDG&E has been working internally and externally to prioritize corrective work in the HFTD to minimize deferrals. For example, SDG&E has been working cooperatively with the Caltrans on a process that would allow SDG&E to complete work prior to going through the permitting process and obtain an “after-the-fact" encroachment permit. This would allow SDG&E to make the facility “safe” quickly and satisfy Caltrans administrative requirements. Unfortunately, customer access issues continue to present challenges in the timely closure of corrective work orders. SDG&E is continuing outreach and education efforts, as well as clarification of land rights, to either avoid or support resolution of access issues.

8.1.7.4 Trends with Respect to Open Work Orders

In general, average timelines to resolve open work orders in the HFTD have been maintained over the past 3 years with an average of 5 months or less in Tier 3, less than 7 months in Tier 2, and less than 45 days for Level 2 severity items across the entire HFTD.

See Section 8.1.1.3 Performance Metrics for grid inspection findings and open work orders.

Further analysis is performed when recurring infractions and conditions are identified through inspections and proactive replacement/repair projects can be initiated. See Section 8.1.4 Equipment Maintenance and Repair for details on proactive maintenance and replacement strategies.

8.1.7.5 Open work orders over time

Figure 8-24 shows the number of open distribution work orders, including past due orders, by year. On average, there are 267 open orders as of year-end, of which approximately 2.5 percent are past due. The number of open orders has trended up since 2019 due to additional drone inspections performed in the HFTD. The DIAR Program (WMP.552) is transitioning its methodology to inspect the top 15 percent HFTD structures by risk each year moving forward, which will level out the number of open work orders moving forward.

Figure 8-24: Distribution Open Work Orders

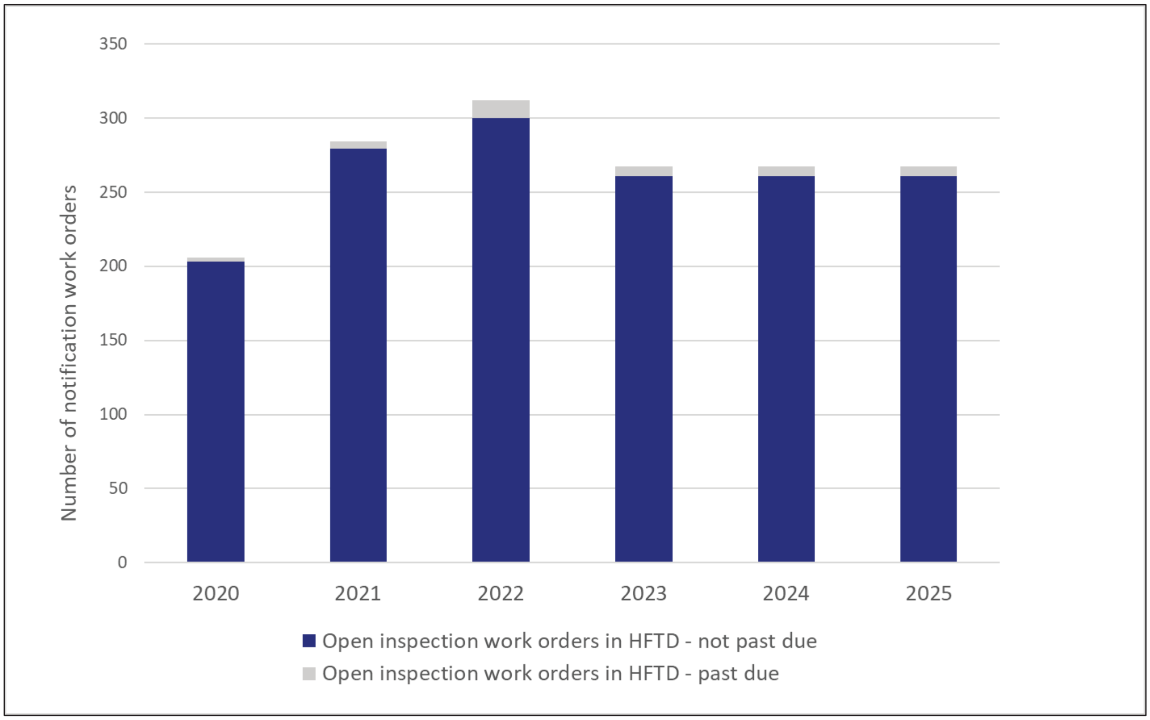
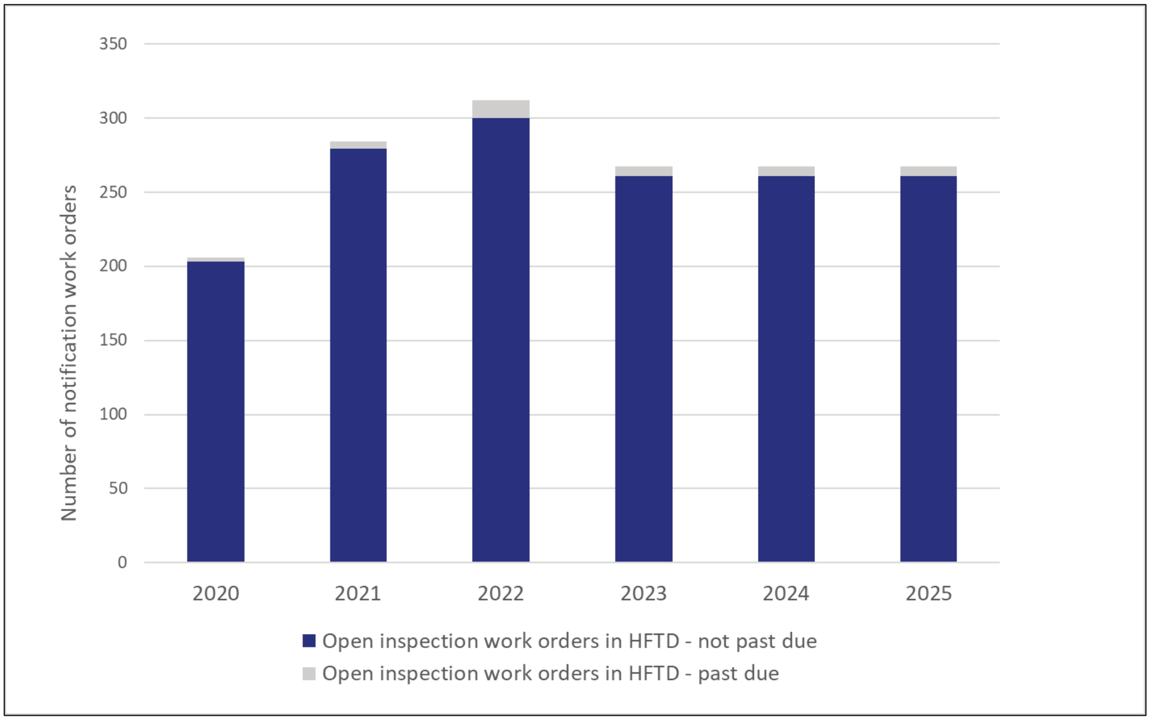


Figure 8-25 shows the number of open transmission work orders by year. On average, there are 206 open work orders as of year-end. A downward trend is observed, and this trend is forecasted to be in line with the average for the last 2 years. Transmission inspection had zero past due open work orders in the last 3 years. This performance is forecasted to continue in the next 3 years.

Figure 8-25: Transmission Open Work Orders – Not Past Due



8.1.7.6 Aging report for work orders past due

All past due work orders are non-emergency or deferred work under reasonable circumstances per GO 95. SDG&E implements processes where deferred work is reviewed, prioritized, and solutions are determined to remediate issues on a monthly basis. SDG&E prioritizes work in Tier 3 of the HFTD, and therefore there are currently no past due work orders within Tier 3. The obstacles and mitigation strategies associated with past due work orders are described in Section 8.1.7.3. OEIS Table 8-8 shows an aging report for current past due work orders.

OEIS Table 8-8: Number of Past Due Work Orders Categorized by Age

HFTD Area	0-30 Days	31-90 Days	91-180 Days	181+ Days
Transmission HFTD Tier 2	0	0	0	0
Transmission HFTD Tier 3	0	0	0	0
Distribution HFTD Tier 2	0	0	0	0
Distribution HFTD Tier 3	0	0	0	0

8.1.8 Grid Operations and Procedures

8.1.8.1 Equipment Settings to Reduce Wildfire Risk

8.1.8.1.1 Protective Equipment and Device Settings (WMP.991)

Advanced SGF relay settings are employed to ensure proper detection of high impedance ground faults on the electric distribution system in order to prevent potential wildfire ignitions. Additionally, during periods of extreme fire potential risk, SRP settings are enabled to limit fault energy should a fault develop on the electric distribution system. SDG&E has operating procedures that dictate the use of SRP settings, recloser settings, and general service restoration requirements in the HFTD depending on wildfire risk levels. SGF settings are employed year-round on the overhead electric distribution system. In addition, SRP settings are enabled either when the FPI (WMP.450) has a rating of Extreme or when general conditions may warrant a PSPS event.

A study was completed to determine the impact of sensitive relay settings at reducing ignitions from risk events. During days with an FPI rating of Extreme or during RFWs (WMP.082), sensitive relay settings are enabled on reclosers within the HFTD and coastal circuits with fire risk. The sensitive relay settings should improve the sensitivity of fault detection, the speed at which faults are cleared, and reduces the energy of the fault as much as possible, which reduces the heat generated by a fault, which should lead to fewer ignitions.

The study demonstrated a reduction in ignition percentage from 3.02 percent to 0 percent (see SDG&E Table 8-29). From 2015 to 2021, there were zero ignitions by primary faults downstream of devices with sensitive relay settings enabled. While there are not enough samples for the data to show a statistically significant reduction, the early results are promising.

SDG&E Table 8-29: Ignition Rate with SRP Enabled

Description	Calculation
Total System Risk Events	3,010
Total System Ignitions	91
Percent System Ignitions	3.02%
Total Risk Events with SRP	90
Tier 2 Events with SRP	49
Tier 3 Events with SRP	41
Total Ignitions with SRP	0
Percent Ignition with SRP	0%
Percent Decrease in Ignition with SRP Enabled	100%

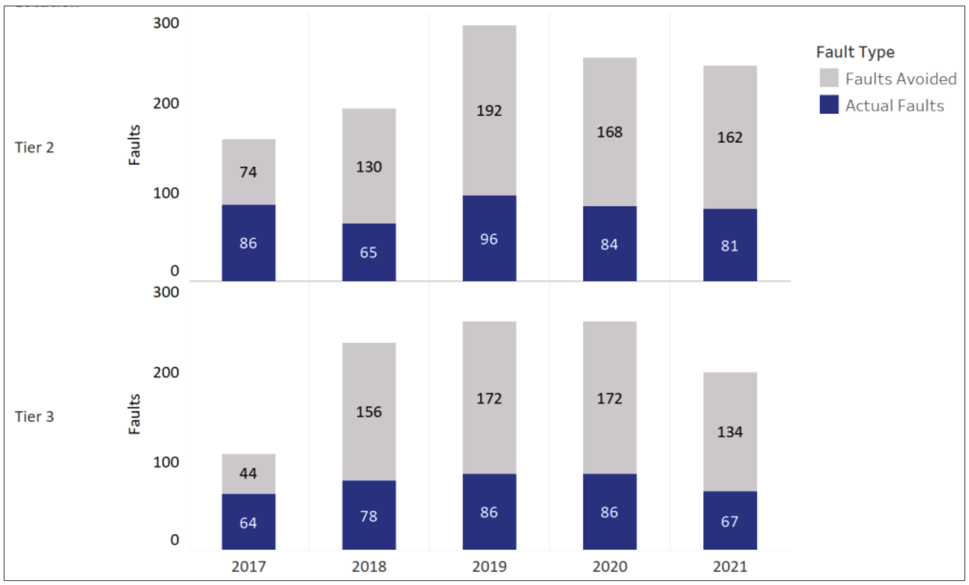
8.1.8.1.2 Automatic recloser settings (WMP.1018)

Reclosing settings have been turned off since 2017 in the HFTD. Manual reclosing is performed without patrol only when the FPI rating is Normal. SDG&E does not enable automatic recloser settings in the HFTD, and 100 percent of overhead lines have reclosing capabilities. Reclosing settings are not changed in response to off-normal events.

A study was conducted to understand the effectiveness of recloser protocols. Prior to 2017, reclosing in the HFTD was disabled on days with an FPI rating of Elevated or Extreme. After 2017, reclosing was disabled in the HFTD all year regardless of the FPI rating to further reduce the risk of ignitions. This study reviewed historical risk events that were isolated by reclosers to measure the effectiveness of disabling reclosing at reducing faults and ignitions over the last 5 years. By measuring faults on the system by HFTD Tier and weather condition, the number of additional faults avoided by turning reclosing off under certain conditions was estimated. The faults avoided were then multiplied by the relevant HFTD ignition rate to estimate the number of ignitions avoided per year.

The results show that disabling reclosing reduces ignitions by an average of 4.2 per year in Tier 2 of the HFTD and 4.7 per year in Tier 3 of the HFTD (see SDG&E Table 8-30).

Figure 8-26: Results of Reclosure Protocols in Fault Avoidance



SDG&E Table 8-30: Results of Reclosure Protocols in Ignition Avoidance

Year	Estimated Ignition Avoided: Tier 2	Estimated Ignition Avoided: Tier 3	Estimated Ignition Avoided: Total
2017	3.4	2.4	5.8
2018	4.3	5.0	9.3
2019	4.8	5.6	10.4
2020	4.2	6.4	10.7
2021	4.3	3.9	8.3
5 Year Avg.	4.2	4.7	8.9

8.1.8.1.3 Settings of other Emerging Technologies

SDG&E does not employ Rapid Earth Fault Current Limiters.

8.1.8.2 Grid Response Procedures and Notifications

Multiple technologies are deployed to narrow the location of detected issues on the system including the use of SCADA (WMP.453) and Wireless Fault indication (WMP.499). Additionally, predictive fault analytics technology is being developed that can identify potential locations of emerging faults on the system. Lastly, if an issue is intermittent and not found during patrol and subsequent service restoration, an after-event fault analysis is performed to simulate and investigate potential fault locations in order to resolve the issue.

Priorities are based on customer impacts unless a fire ignition or other safety issue is present, in which case those incidents would take priority. If no safety issue is present, critical public infrastructure is given the highest priority, after which resources are deployed to the incidents with the largest customer impacts.

SDG&E has multiple channels for detecting wildfire ignitions. Fire Coordination notifies all personnel of any fire ignitions in close proximity to SDG&E infrastructure, and Electric Troubleshooters are dispatched to any outage on the system detected through customer calls or advanced metering alarms.

During PSPS events and high-fire risk weather events, any new outages on the electric system are closely monitored and fire alert cameras (WMP.1343) are rotated to the de-energized area to look for potential ignitions. If an ignition is detected, Fire Coordination will immediately notify the proper fire authority to initiate fire suppression. Similarly, at the conclusion of a PSPS event, CFR are staged in close proximity to each area being restored in an effort to prevent ignitions and mitigate any ignition that occurs. All fire activities are coordinated with first responders and training is performed throughout the year to ensure efficient coordination during real world incidents.

SDG&E expands resources to minimize response times based on wildfire risk levels. During days with an FPI rating of Extreme or conditions that generally warrant a PSPS, staffing of emergency responders is increased around the clock and staff is placed in the areas of highest risk in order to minimize response times.

8.1.8.3 Personnel Work Procedures and Training in Conditions of Elevated Fire Risk (WMP.515)

Work activities and associated fire mitigations throughout the service territory are designated for specific Operating Conditions (e.g., Normal condition, Elevated condition, Extreme or RFW) as outlined in the Electric Standard Practice (ESP) document: *SDG&E Operations and Maintenance Wildland Fire Prevention Plan* (ESP 113.1). As the fire potential increases in severity, activities that present an increased risk of ignition have additional mitigation requirements. Where risk cannot be mitigated, work activity might cease. All field personnel are required to be trained on SDG&E's fire prevention procedures annually. Fire prevention and safety is also discussed at pre-job briefings, commonly referred to as tailgates/tailboards, and built into standard work practice. These standard practices are not exclusive to the HFTD and are implemented in all areas of the service territory where at-risk activities are performed adjacent to wildland fuels.

8.1.8.3.1 Procedures for Determining Operating Conditions

Procedures and routine practices for working in wildland areas of the service territory are detailed in (ESP 113.1). Risk levels are determined by the FPI rating for that zone of the service territory.

The following summarizes the work activity guidelines for each Operating Condition:

- Normal Condition: Normal operating procedures are followed with baseline tools present at work sites, appropriate buffers between heat sources and flammable fuels, and equipment meeting appropriate standards.
- Elevated Condition: Certain at-risk work activities may require additional mitigation measures in order to proceed with work. Additional mitigations may include but are not limited to a Dedicated Fire Patrol, additional water on site, and/or barriers between work and vegetation.
- Extreme or RFW Condition: Most overhead work activities will cease except where not performing the work would create a greater risk than doing so. In those cases where at-risk work needs to be performed, a Fire Coordinator is consulted and additional mitigation steps are implemented. Status of work, ceased or continued, is documented.

All field personnel are trained annually in ESP 113.1, the document that governs work practices during different wildfire risk levels. Field personnel and operating teams receive emails when operating conditions change or daily, whichever is more frequent. Additionally, the current FPI is made available via a weather application and website.

A study was performed to determine the effectiveness of special work procedures that cancel all work in the HFTD Tier 3 and Tier 2 on days with an FPI rating of Extreme. Based on historical crew-caused risk events, special work procedures mitigate 0.0317 ignitions annually in Tier 2 and 0.0361 ignitions annually in Tier 3 of the HFTD (see SDG&E Table 8-31).

SDG&E Table 8-31: Effect of Special Work Procedures on Ignitions

Description	Tier 2	Tier 3
Risk Events	0.2	0.3
Ignition Rate	12.90%	10.53%
Ignition Avoided	0.0317	0.0361

8.1.8.3.2 Crew Accompanying Ignition Prevention and Suppression Resources and Services (WMP.514)

SDG&E worksites are required to have increasing levels of wildfire prevention mitigation based on the activity being performed and the FPI rating as stated in ESP 113.1. This could be as simple as carrying wildfire suppression tools to having a dedicated Fire Resource observing work.

When work activities reach a level of fire risk where a dedicated resource is required, SDG&E and contract personnel utilize a qualified fire resource with specific training and experience (listed in ESP 113.1). While these resources can be ordered throughout the year to meet California’s year-round fire season, SDG&E takes the proactive step of supplying field crews with 12 to 17 daily resources once the fire environment and FPI begin to indicate elevated risk. This daily staffing changes from year to year but typically runs from roughly June [t] through the end of November. SDG&E also works to align with the staffing of the seasonal resources of the local, state, and federal agencies in the service territory.

These qualified resources, referred to as CFRs, are staffed by two personnel that have the appropriate amount of training, water, and tools to meet the needs of the work activity. The use of CFRs is not limited to the HFTD as ESP 113.1 requires a dedicated fire patrol for specific activities when they are performed adjacent to wildland fuels and there is elevated risk. The primary missions of CFRs are fire prevention and compliance. Secondarily, because of the required training tools, the resource can take action to mitigate an ignition should it occur and communicate to the fire agencies to ensure transparent reporting. At-risk activities for which a dedicated fire patrol is utilized include but are not limited to hot work, vegetation clearing, and energized switching.

During periods of Extreme Fire Potential, SDG&E cancels regular work with at risk activities. CFRs are deployed with SDG&E personnel for emergency work and play an important role in fire prevention during the PSPS de-energization and restoration process.

A study was performed to determine the effectiveness of special work procedures that require CFRs on days that with an FPI rating of Elevated or higher.

CFRs perform preconstruction mitigation measures such as watering down the work area. Should a risk event occur that leads to an ignition, the teams work to suppress the ignition before it can grow in an attempt to limit the impacts. This research concluded that the use of CFRs mitigates 0.0785 ignitions in Tier 2 per year and 0.1896 ignitions in Tier 3 annually.

SDG&E Table 8-32: Effect of CFRs on Ignitions

Description	Tier 2	Tier 3
Risk Events	2.2	3.8
Ignition Rate	3.57%	4.99%
Ignition Avoided	0.0785	0.1896

8.1.8.3.3 Aviation Firefighting Program (WMP.557)

The Aviation Firefighting Program (WMP.557) focuses on reducing the consequences of wildfires through suppression of fire spread. These resources are available not only for fires associated with SDG&E equipment but to the entire community regardless of the cause of ignition. Under certain conditions, a wildfire that is not suppressed may grow rapidly and uncontrollably and endanger public safety. Fire agencies could divert local aerial resources to fight wildfires outside of the service territory, leaving the service territory with limited or no aerial firefighting resources. To mitigate this risk, the aviation firefighting program serves as a wildfire suppression resource, ensuring aerial firefighting resources remain available in the region.

Two firefighting helicopters, an Erickson S-64 helitanker and a Sikorsky UH-60 Blackhawk helitanker are available. Both firefighting assets are Type 1 firefighting helicopters, defined as carrying over 700 gallons of water to fight fires. The Air Crane has the capability of dropping up to 2,650 gallons of water and the Blackhawk has the capability of dropping up to 850 gallons of water. Additionally, the Blackhawk hardware is configured for night vision device flight and is capable of night firefighting with the appropriate crew, training, and CAL FIRE support. The decision for these two resources was based on their exceptional fire suppression capability and ability to perform as a construction tool in areas with access issues. In 2022 a Sikorsky S-70M was purchased which is being outfitted for firefighting with a 1,000-gallon tank. Due to certification requirements of the Federal Aviation Administration (FAA), it is estimated that this helicopter will not be in service until the end of 2024 or early 2025.

SDG&E has agreements with the County of San Diego, CAL FIRE, and the Orange County Fire Authority for aerial firefighting within the service territory. Dispatch of aviation firefighting assets is performed through CAL FIRE and these assets support the initial attack strategy to contain wildfires to less than 10 acres. SDG&E employs flight operations staff to assist in dispatching aerial assets 365 days per year, throughout the service territory. This allows the assets to be launched rapidly once dispatched by CAL FIRE.

Generally, helicopters that drop water need to be relatively close to their target, and the stronger the wind the more dangerous it becomes to fly close to the ground. In addition, strong winds can help dissipate the water from the aircraft and lead to ineffective water drops.

SDG&E will continue to analyze the most effective way to run its Aviation Firefighting Program, and to determine the effectiveness of that program using internal and external data to assist in the analysis.

The effectiveness of the Aviation Firefighting Program will continue to be analyzed using internal and external data. The current subject matter expert consensus is that the program reduces overall wildfire consequence, and therefore wildfire risk, by approximately 4 percent; based solely on the knowledge of the equipment and operations, coupled with anecdotal evidence of recent history. Importantly, this 4 percent is only the measure of utility associated wildfires, and the overall benefit of the program is much larger than what that 4 percent represents.

8.1.9 Workforce Planning

OEIS Table 8-9: Workforce Planning, Asset Inspections

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Distribution							
Line Inspector	• Successful completion of 6-month Overhead Detailed Inspection training program • IBEW status in good standing • Valid California driver's license	Overhead and underground Inspection Training	0%	n/a	0%	n/a	Overhead CMP Detailed Inspection Training (STU EL310)
Distribution Lineman	• Journeyman Lineman having completed an accredited apprenticeship program • International Brotherhood of Electrical Workers (IBEW) Journeyman Lineman status in good standing • Class A California Driver's License	*Qualified electrical worker (QEW), Overhead and/or Underground Inspection Training	54%	100%	0%	n/a	Line Assistant and Apprenticeship Program
Fault Finding Specialist	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • 4-week Relief Fault Finder (RFF) class completed and associated written and practical exams passed	*QEW, Overhead and/or Underground Inspection Training	2%	100%	0%	n/a	Line Assistant and Apprenticeship Program RFF Course

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Electric Troubleshooter	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Complete 7-week Relief Trouble Shooter (RETS) class and pass written and practical exams	*QEW, Overhead and/or Underground Inspection Training	14%	100%	0%	n/a	Line Assistant and Apprenticeship Program
Working Foreman	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • 6 months' experience in both overhead and underground electric during the past three years • Construction Standards and Practices tests passed	*QEW, Overhead and/or Underground Inspection Training	12%	100%	0%	n/a	Line Assistant and Apprenticeship Program
Distribution Construction Supervisor	• 6+ years construction and maintenance experience	*QEW, Overhead and/or Underground Inspection Training	18%	100%	0%	n/a	Line Assistant and Apprenticeship Program Essentials of Supervision
Inspection and Treatment Foreman	• Pesticide handler training • Valid class C driver's license • 1st aid/CPR qualified	n/a	0%	n/a	86%	n/a	n/a
Auditor	• 2 weeks auditor training	n/a	0%		14%	n/a	n/a
Distribution Total			**100%**		**100%**		

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Transmission							
Transmission Lineman	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing Class A California Driver's License	*QEW, Overhead and/or Underground Inspection Training	34%	100%	0%	n/a	Line Assistant and Apprenticeship Program
Transmission Patroller	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Class A California Driver's License 18 months experience in overhead and underground transmission construction and maintenance within the past 3 years	*QEW, Overhead and/or Underground Inspection Training	7%	100%	0%	n/a	Line Assistant and Apprenticeship Program
Working Foreman-Electric Transmission	• Journeyman Lineman having completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Valid California Class A driver's license • Class A Medical Certificate 18 months' experience in transmission construction and Energized High Voltage hotline	*QEW, Overhead and/or Underground Inspection Training	7%	100%	0%	n/a	Line Assistant and Apprenticeship Program

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
	maintenance within the past 5 years						
Thermographer	• Part 107 drone license or must obtain within first year Level I Infrared Certification or must obtain within first year	Thermography certificate *QEW or Electrician	9%	100%	0%	n/a	
Senior Thermographer	• Part 107 drone license or must obtain within first year Level III IR Certification or must obtain within first year	Thermography certificate *QEW or Electrician	3%	100%	0%	n/a	
Transmission Construction Supervisor	6+ years–- Construction and maintenance experience	*QEW, Overhead and/or Underground Inspection Training	40%	100%	0%	n/a	Line Assistant and Apprenticeship Program Essentials of Supervision
Inspection and Treatment Foreman	• Pesticide handler training • Valid class C driver's license 1st aid / CPR qualified		0%	n/a	100%	n/a	
Transmission Total			100%		100%		
Substation							
Substation Inspector	• Substation Electrician Journeyman having completed electrician apprenticeship program Valid California Class A driver's license	*QEW	75%	100%	0%	n/a	Electrician Apprenticeship Program
Substation Construction Supervisor	Journeyman with 5+ year'' experience	*QEW	25%	100%	0%	n/a	Electrician Apprenticeship Program

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
							Essentials of Supervision
Total			**100%**				

OEIS Table 8-10: Workforce Planning, Grid Hardening

Worker Titles	Minimum Qualifications	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Distribution							
Apprentice Lineman	• 9 months' experience as Line Assistant • Valid California driver's license • Must have held previous position for at least 9 months	No special certification required	19%	n/a	15%	n/a	Line Assistant and Apprenticeship Program
Cable Splicer	• Journeyman Lineman	No special certification required	0%	n/a	9%	100%	Line Assistant and Apprenticeship Program
Construction Manager-Electric	• Bachelor's Degree or equivalent experience • 8 years' experience	No special certification required	2%	n/a	0%	n/a	Essentials of Supervision
Construction Supervisor-Electric	• High School Diploma or GED • 6 years' experience	No special certification required	13%	n/a	0%	n/a	Line Assistant and Apprenticeship Program Essentials of Supervision

Worker Titles	Minimum Qualifications	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
	• Complete 2-day program at Skills Training Center or complete outside program						
District Manager	• High School Diploma or GED • 10 years' experience	No special certification required	2%	100%	0%	n/a	Essentials of Supervision
Electric Troubleshooter	• Complete 7-week RETS class and pass written and practical exams	Journeyman Lineman	10%	100%	0%	n/a	Line Assistant and Apprenticeship Program RETS Training
Fault Finder	• Complete 4-week RFF class and pass written and practical exams	Journeyman Lineman	1%	100%	0%	n/a	Line Assistant and Apprenticeship Program RFF Training
Field Construction Advisor (FCA)	• Journeyman Lineman	QEW	0%	n/a	7%	100%	Line Assistant and Apprenticeship Program
Foreman	• Journeyman Lineman	QEW	0%	n/a	17%	100%	Line Assistant and Apprenticeship Program
Foreman (Splicing)	• Journeyman Lineman	QEW	0%	n/a	2%	100%	Line Assistant and Apprenticeship Program
Groundman	n/a	No special certification required	0%	n/a	2%	n/a	n/a
Journeyman Lineman	• Journeyman Lineman	QEW	0%	n/a	48%	100%	Line Assistant and Apprenticeship Program
Line Assistant (non QEW)	• Successfully pass Company administered aptitude and skills tests	No special certification required	6%	n/a	0%	n/a	Line Assistant and Apprenticeship Program

Worker Titles	Minimum Qualifications	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
	• Valid California Class A driver's license • Pass a Department of Motor Vehicles (DMV) physical examination and Department of Transportation (DOT) drug screen • Must have held previous position for at least 9 months						
Distribution Lineman	• Complete the minimum 3-year 6000-hour Lineman Apprentice program at the Skills Training Center and assigned Districts • Complete a 3-year, 480-hour college-level program to be qualified to take the Journeyman Lineman's test • Pass the Journeyman Lineman test	QEW	39%	100%	0%	n/a	Line Assistant and Apprenticeship Program
Working Foreman-Electric Distribution	• 6 months' experience in both overhead and underground electric during the past 3 years • Valid California Class A driver's license • Class A Medical Certificate • Must have held previous position for at least 9 months	QEW	8%	100%	0%	n/a	Line Assistant and Apprenticeship Program
Total			**100%**		**100%**		

Worker Titles	Minimum Qualifications	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Transmission							
Construction Manager-Electric	• Bachelor's Degree or equivalent experience • 8 years' experience	QEW	4%	100%	0%	n/a	Essentials of Supervision
Construction Supervisor-Electric	• High School Diploma or GED • 6 years' experience	No special certification required	27%	n/a	0%	n/a	Line Assistant and Apprenticeship Program Essentials of Supervision
Line Assistant (non QEW)	• Successfully pass Company administered aptitude and skills tests • Valid California Class A driver's license • Pass a DMV physical examination and DOT drug screen • Must have held previous position for at least 9 months	No special certification required	6%	n/a	0%	n/a	Line Assistant and Apprenticeship Program
Team Lead	• Bachelor's Degree or equivalent experience • 5 years' experience • Professional Engineer License	No special certification required	8%	n/a	0%	n/a	n/a
Transmission Lineman	• Complete the minimum 3-year 6000-hour Lineman Apprentice program at the Skills Training Center and assigned Districts	QEW	24%	100%	0%	n/a	Line Assistant and Apprenticeship Program

Worker Titles	Minimum Qualifications	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
	• Complete a 3-year, 480-hour college-level program to be qualified to take the Journeyman Lineman's test • Pass the Journeyman Lineman test						
Transmission Patroller	• Valid California Class A driver's license • Class A Medical Certificate • 18 months experience in overhead and underground transmission construction and maintenance within the past 3 years • Must reside within the service territory	QEW	4%	100%	0%	n/a	Line Assistant and Apprenticeship Program
Working Foreman-Electric Transmission	• Valid California Class A driver's license • Class A Medical Certificate • 18 months' experience in transmission construction and EHV hotline maintenance within the past 5 years • Must have held previous position for at least 9 months	QEW	27%	100%	14%	100%	Line Assistant and Apprenticeship Program Essentials of Supervision
Field Construction Advisor (FCA)	• Journeyman Lineman	QEW	0%	n/a	24%	100%	Line Assistant and Apprenticeship Program

Worker Titles	Minimum Qualifications	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Apprentice Lineman	n/a	No special certification required	0%	n/a	4%	n/a	n/a
Journeyman Lineman	• Journeyman Lineman	QEW	0%	n/a	45%	100%	Line Assistant and Apprenticeship Program
Groundman	n/a	No special certification required	0%	n/a	2%	n/a	n/a
Operator	• Crane license, if operating a crane	No special certification required	0%	n/a	11%	n/a	n/a
Total			**100%**		**100%**		

OEIS Table 8-11: Workforce Planning, Risk Event Inspection

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Electric Troubleshooter	• Journeyman Lineman who completed an accredited apprenticeship program • IBEW Journeyman Lineman status in good standing • Complete 7-week RETS class and pass the associated written and practical exams	QEW	100%	100%	0%	n/a	RETS Training Line Assistant and Apprenticeship Program
Total			**100%**		**0%**		

8.1.9.1 Asset Inspection Workforce Planning Improvement Plans (WMP.1334)

8.1.9.1.1 Extended Reality

SDG&E is exploring and implementing extended reality for PSPS Pre-Patrol inspections for new qualified electrical workers (QEWs), apprentices, and support personnel to better understand the PSPS pre-patrol procedures and distinguish between fire hazard and non-fire hazard conditions. Over 350 employees have completed an extended reality PSPS training since its development in 2022. QEW employees were surveyed after training and 80 percent responded that they believed the extended reality training was helpful in learning the role and procedure for PSPS Patrols.

8.1.9.1.2 Line Checker Program

Line Checker is a new classification in development for 2023. Line Checkers will be required to complete a 7-month training program to conduct detailed inspections as per GO 95, 128, 165 and SDG&E Construction Standards. Line Checkers will perform patrols, detailed visual inspections, and ground level onsite corrective maintenance. They will be limited to what can be performed safely without a QEW present. In addition to extensive classroom training and ride-alongs, Line Checkers will be expected to complete a 4-month probationary period to develop their proficiency in the field. This probationary period will include individual QA reviews on completed inspections.

8.1.9.1.3 Safety Observations

SDG&E tracks safety observations performed across all districts and organizations, including both supervisor/leadership observations as well as peer-to-peer observations. Operational leadership is encouraged to conduct safety observations of the workforce in the field and the office. These safety observations build trust and promote psychological safety across all levels of the workforce.

Peer-to-peer observations take place within SDG&E's Behavior Based Safety (BBS) program. SDG&E's BBS program is a proactive approach to safety management, focusing on principles that recognize at-risk behaviors as a frequent cause of both minor and serious injuries. The purpose of this program is to reduce the occurrence of at-risk behaviors by modifying an individual's actions and/or behaviors through observation, feedback, and positive interventions aimed at developing safe work habits. Identified risks and hazards are documented and best practices and lessons learned are shared real-time with personnel being observed.

Employee safety observations are documented and reported to SDG&E's Safety business unit for enterprise transparency and accountability. Annual goals are set and tracked as a safety culture leading indicator. SDG&E also performs safety observations and jobsite safety inspections of this third-party contractor workforce. While SDG&E tracks its contractor safety observations and inspections, those figures are not included in this metric. SDG&E Table 8-33 includes SDG&E's historical performance metrics for employee-conducted Safety Observations. These metrics are included in Table 3 of the QDR.

SDG&E Table 8-33: Employee-Conducted Safety Observations

Year	Safety Observations
2018	9,157
2019	11,843

Year	Safety Observations
2020	15,801
2021	17,178
2022	20,355

8.1.9.1.4 Near Misses Reported

"Near Misses" are circumstances where "no property was damaged and no personal injury was sustained, but where, given a slight shift in time or position, damage [and/or] injury easily could have occurred," consistent with the use of those terms by Occupational Safety and Health Administration (OSHA) in its Near-Miss Incident Report Form template.[29] Near Miss Reporting provides employees and contractors the means to communicate safety concerns (anonymously, if desired), and provides SDG&E with an opportunity to identify potential risks/hazards, raise awareness, share lessons learned, perform data analytics, and implement proactive safety improvements, when applicable, to prevent future incident or injury.

A Near Miss submittal is recognized as a leading indicator safety statistic. Lagging indicators, like OSHA injury statistics, can provide information on a failure in an area of a safety and health program or the existence of a hazard. Leading indicators allow preventive action to be taken that addresses that failure or hazard before it turns into an incident. Near Misses provide SDG&E with an opportunity to increase awareness of a potential risk or hazard and take proactive action to implement safety improvements, where applicable, to prevent future injury or incident.

Near Misses can be submitted via an online portal or smart phone mobile application. All personnel are encouraged to share near miss events as they occur and report to SDG&E's Safety business unit. Near miss events are then shared broadly and tracked with appropriate follow-up and feedback. SDG&E collects and separately tracks Contractor-submitted Near Miss reports. SDG&E Table 8-34 includes SDG&E's historical performance metrics for employee-submitted Near Misses. These metrics are included in Table 3 of the QDR.

SDG&E Table 8-34: Employee-Submitted Near Misses

Year	Near Misses
2018	65
2019	83
2020	111
2021	251
2022	371

[29] https://www.osha.gov/sites/default/files/2021-07/Template%20for%20Near%20Miss%20Report%20Form.pdf

8.1.9.2 Grid Hardening Workforce Planning Improvement Plans (WMP.1331)

SDG&E maintains ESP 113.1 for Wildland Fire Operations and Maintenance specific to Wildland Fire Prevention. The intent of ESP 113.1 is to formalize procedures and routine practices to assist employees, contractors, and consultants in their understanding of wildfire prevention and to improve their ability to prevent the start of any fire. Updates to ESP 113.1 are done on an annual basis and communicated to employees, contractors, and consultants.

In addition, Grid Hardening enhances the training and qualifications of their workers by providing a constant feedback loop on the job. This is done through post construction inspections and true-ups of as-builts using LiDAR technology.

The QA/QC teams complete post construction inspections, which compares the project build to the design guide. Any errors, omissions, or craftsmanship improvements are provided to the workers to enhance their knowledge and skills for future projects.

The true-up of as-builts using LiDAR technology compares the project build to the PLS-CADD design, which models the as-built condition. Any discrepancies between the as-built model and the as-built are reviewed with workers to identify lessons learned to update the design guide when appropriate.

8.1.9.3 Risk Event Inspection Workforce Planning Improvement Plans (WMP.1206)

Risk event inspection improvement plans include modernizing training utilizing virtual reality for overhead CMP and PSPS patrols and observer roles.

8.2 Vegetation Management and Inspection

8.2.1 Overview

SDG&E continues to address the risk of vegetation-infrastructure contact outages and ignitions through its comprehensive Vegetation Management Program. In 2022, the Vegetation Management Program continued its successes in tracking and maintaining its inventory tree database (WMP.511), completing routine and enhanced tree patrols (WMP.494 and WMP.501 respectively), pruning and removing hazardous trees (WMP.508), replacing unsafe trees with species that are more compatible with powerlines (WMP.1325), and pole brushing (WMP.512). This resulted in inspections of over 500,000 trees across the service territory, over 35,000 poles brushed, and nearly 10,500 trees trimmed beyond regulatory clearances. SDG&E's WMP vegetation management initiatives span several activities including inspections, trimming and removals, fuels treatment, pole brushing, and audit.

Inspections consist of an annual, detailed, and documented inspection activity of each inventory tree record within the service territory. Inventory trees are systematically assigned a unique alpha-numeric identification. Data collected on each inventory tree includes property location, customer information, span location, GPS coordinates, species, line clearance, growth rate, diameter at breast height (DBH), prune status, and tree health.

Fuels Management (WMP.497) is a vegetation thinning activity that entails enhanced clearing around inventoried subject poles located within the HFTD that carry hardware that are subject to pole brushing requirements in PRC § 4292. This fuels treatment program is not regulatory-required and is a discretionary activity SDG&E performs as an additional risk mitigation. Data collected includes property location, customer information, span location, GPS coordinates, work status, and history.

PowerWorkz, the Vegetation Management Program's system of record, consists of CityWorks, a centralized server for the creation of electronic work orders associated with Vegetation Management activities, and a database of all tree inventory records. It also includes Epoch, the mobile field application where all Vegetation Management assets (tree and pole brush records) are updated by contractors associated with the activities of pre-inspection, tree trimming, pole brushing, and auditing. The fuels management activity is currently not included in this application at this time.

SDG&E activities are reviewed for environmental and cultural impact and released to perform work by identifying any applicable constraints or restrictions to ensure species and habitat protection in accordance with environmental rules and regulations.

Vegetation Management performs a QA/QC audit (WMP.505) on a percentage of all activities. In general, a 15 percent sample is selected to be performed after activities are completed. Vegetation Management performs an audit on 100 percent of all hazard tree and tree removal activities completed which result from the off-cycle, HFTD inspection activity.

All scheduled trimming activities are recorded in the tree asset record within the electronic inventory database. Upon work completion, the tree trim records are updated with a work status (condition code) and timestamp. Tree work is issued and tracked via electronic parent SWO within each Vegetation Management Area (VMA). Contractors in turn create multiple child DWO within each SWO to distribute to the field crews. Upon completion of the field work, contractors complete the DWOs and the assigned SWOs in the database. Condition codes and dates completed are used to track and prioritize work completion at the individual tree level, and within the associated work orders. Work orders can be ascribed high priority to be completed in a more urgent timeframe

Vegetation Management works with its contractors to determine the level of staffing required to complete all activities following the annual Master Schedule. Contractors are required to provide the necessary training to their workforce on the technical capabilities to perform the work. SDG&E collaborates externally with the San Diego Community College District, Utility Arborist Association, local International Brotherhood of Electrical Workers (IBEW) union, and other IOUs in the development and execution of a Line Clearance Arborist Training program. Should additional resources be required to address emergency work, SDG&E relies on its contractor to attain subcontracted resources and/or mutual-aid support from the neighboring utilities.

8.2.1.1 Objectives

OEIS Table 8-12: Vegetation Management Initiative Objectives (3-year plan)

Objective Number	Objectives for Three Years (2023–2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.2.01	Create new attribute fields within tree inventory database to document site-specific and tree-specific risk conditions.	Vegetation Management Enterprise System WMP.511	n/a	n/a	12/31/2025	8.2.4, p. 287
8.2.02	Vegetation Management Enterprise System	Vegetation Management Enterprise System WMP.511	n/a	n/a	12/31/2025	8.2.4, p. 287
8.2.03	Create system on server-side application to auto-close Dispatch Work Orders upon closure of Scheduling Work Orders	Vegetation Management Enterprise System WMP.511	n/a	n/a	12/31/2025	8.2.4, p. 287
8.2.04	Integrate risk-analysis into annual, off-cycle HFTD and at-risk patrols	Off-Cycle Patrols; WMP.508	n/a	n/a	12/31/2025	8.2.3.5, p. 284
8.2.05	Continue pole clearing (brushing) including multiple, annual activities of mechanical, chemical, and re-clear activities to prevent ignitions. Continue pole brushing in areas not required by law as an added fire-prevention activity. Continue integrated TGR application during the pre-inspection process.	Pole Clearing, “Brushing”; WMP.512	*PRC § 4292	Completed work orders/ GIS Data Submission(s)	12/31/2025	8.2.3.1, p. 278
8.2.06	Continue to thin flammable vegetation around select poles subject to PRC § 4292 using risk and environmental impact criteria. Pilot alternate methods of thinning such as the cultural use of goats for sustainability goals.	Fuels Management Program; WMP.497	*PRC § 4292	Completed work orders/ GIS Data Submission(s)	12/31/2025	8.2.3.1, p. 278
8.2.07	Continue performing multiple inspection activities in the HFTD including "Level-2" hazard tree patrols within the entire "utility strike zone" to identify risk trees that could impact the overhead conductor	Off-Cycle Patrols; WMP.508	• PRC § 4293 • GO 95, Rule 35	Completed work orders/ GIS Data Submission(s)	12/31/2025	8.2.3.3, p. 282

Objective Number	Objectives for Three Years (2023–2025)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.2.08	Continue pursuing expanded trim clearances greater than 12 feet in the HFTD for targeted species, exceeding regulatory requirements. Update methodology for modeling and forecasting application of enhanced clearances	Clearance, "Enhanced"; WMP.501	• *PRC § 4293 • GO 95, Rule 35	Completed work orders/ GIS Data Submission(s)	12/31/2025	8.2.3.2, p. 281
8.2.09	Continue annual, required, internal contractor training for Hazard Tree, Environmental, Fire Preparedness, and Environmental Regulation. Develop and document internal training material for new Vegetation Management personnel	Workforce Planning WMP.506	n/a	Workforce Planning	12/31/2025	8.2.7, p. 292
8.2.10	Continue engagement and collaboration with California Community College of Education, UAA, local unions, and Joint IOUs on Line Clearance Tree Trimming training. Expand curriculum to include training for Certified Arborists	Workforce Planning WMP.506	n/a	Workforce Planning	12/31/2025	8.2.7, p. 292

**indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. See Appendix E for further justification.*

OEIS Table 8-13: Vegetation Management Initiative Objectives (10-year plan)

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.2.11	Develop next generation electronic work management system to replace Epoch to enhance data management performance.	Vegetation Management Enterprise System WMP.511	n/a	n/a	12/31/2032	8.2.4, p. 287

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.2.12	Create system on server-side application to auto-close Dispatch Work Orders upon closure of Scheduling Work Orders	Vegetation Management Enterprise System WMP.511	n/a	n/a	12/31/2032	8.2.4, p. 287
8.2.13	Develop process for documentation and verification of inspection activities for non-inventory trees within the work management system.	Vegetation Management Enterprise System WMP.511	n/a	n/a	12/31/2032	8.2.4, p. 287
8.2.14	Continue pole clearing (brushing) including multiple, annual activities of mechanical, chemical, and re-clear activities to prevent ignitions. Continue pole brushing in areas not required by law as an added fire-prevention activity. Continue to replace subject equipment such as hot-line clamps and fuses to reduce ignition potential. Automate change-out notification for pole attachments subject to PRC § 4292. Continue integrated TGR application during the pre-inspection process	Pole Clearing, "Brushing"; WMP.512	*PRC § 4292	Completed work orders/ GIS Data Submission(s)	12/31/2032	8.2.3.5, p. 284
8.2.15	Continue to thin flammable vegetation around select poles using risk and environmental impact criteria. Pilot alternate methods of thinning such as the cultural use of goats for sustainability goals.	Fuels Management Program; WMP.497	*PRC § 4292	Completed work orders/ GIS Data Submission(s)	12/31/2032	8.2.3.1, p. 278
8.2.16	Continue off-cycle HFTD and at-risk species (i.e., Targeted Species; Century plant; bamboo) patrols using risk analysis, to prioritize and schedule using work history, outage frequency, and environmental (meteorology, soil moisture) factors	Off-Cycle Patrols; WMP.508	• PRC § 4293 • GO 95, Rule 35	Completed work orders/ GIS Data Submission(s)	12/31/2032	8.2.4, p. 287

Objective Number	Objectives for Ten Years (2026–2032)	Applicable Initiative(s), Tracking ID(s)	Applicable Regulations, Codes, Standards, and Best Practices (See Note)	Method of Verification (i.e., program)	Completion Date	Reference (section & page #)
8.2.17	Continue pursuing expanded trim clearances greater than 12 feet in HFTD for targeted species, exceeding regulatory requirements. Establish benchmarking for optimal tree removal activities based on species, growth rate, tree density, risk.	Clearance, "Enhanced"; WMP.501	• *PRC § 4293 • GO 95, Rule 35	Completed work orders/ GIS Data Submission(s)	12/31/2032	8.2.3.2, p. 281
8.2.18	Continue annual, required, internal contractor training for Hazard Tree, Environmental, Fire Preparedness, and Environmental Regulation. Develop and document internal training material for new Vegetation Management personnel. Review and implement modifications to annual VMA activity schedule and geographic boundaries to maximize operational efficiency and risk priority.	Workforce Planning WMP.506	n/a	Workforce Planning	12/31/2032	8.2.7, p. 292
8.2.19	Continue engagement and collaboration with California Community College of Education, UAA, local unions, and joint IOU on Line Clearance Tree Trimming training. Expand curriculum to include training for Certified Arborists	Workforce Planning WMP.506	n/a	Workforce Planning	12/31/2032	8.2.7, p. 292

*indicates that the electrical corporation exceeds a particular code, regulation, standard, or best practice. See Appendix E for further justification.

8.2.1.2 Targets

OEIS Table 8-14: Vegetation Management Initiative Targets by Year

Initiative Activity	Tracking ID	2023 Target & Unit	% Risk Impact 2023	2024 Target & Unit	% Risk Impact 2024	2025 Target & Unit	% Risk Impact 2025	Method of Verification
Fuels Management	WMP.497	500 poles	0.6259%	150~~500~~ poles	0.1849%	500 poles	0.6259%	GIS Data Submission(s)

Initiative Activity	Tracking ID	2023 Target & Unit	% Risk Impact 2023	2024 Target & Unit	% Risk Impact 2024	2025 Target & Unit	% Risk Impact 2025	Method of Verification
	(8.2.3)				~~0.6259%~~			
Pole Clearing	WMP.512 (8.2.3.1)	33,010 poles	2.8435%	33,010 poles	2.8435%	22,000 ~~33,010~~ poles	1.9643% ~~2.8435%~~	GIS Data Submission(s)
Clearance	WMP.501 (8.2.3.3)	11,200 trees	0.1034%	11,200 trees	0.1034%	11,200 trees	0.1034%	GIS Data Submission(s)

OEIS Table 8-15: Vegetation Inspections Targets by Year

Initiative Activity	Tracking ID	Target End of Q2 2023 & Unit	Target End of Q3 2023 & Unit	End of Year Target 2023 & Unit	% Risk Impact 2023	Target End of Q2 2024 & Uni	Target End of Q3 2024 & Unit	End of Year Target 2024 & Unit	% Risk Impact 2024	Target End of Q2 2025 & Unit	Target End of Q3 2025 & Unit	Target 2025 & Unit	% Risk Impact 2025	Method of Verification
Detailed Inspection	WMP.494(8.2.2.1)	241,800 inspections	374,200 inspections	485,400 inspections	24.85%	241,800 inspections	374,200 inspections	485,400 inspections	24.85%	127,500 ~~241,800~~ inspections	191,250 ~~374,200~~ inspections	255,000 ~~485,400~~ inspections	15.4936% ~~24.85%~~	GIS Data Submission(s)
Off-Cycle Patrol	WMP.508 (8.2.2.1.1)	9 VMAs	106 VMAs	106 VMAs	n/a	9 VMAs	106 VMAs	106 VMAs	n/a	9 VMAs	106 VMAs	106 VMAs	n/a	GIS Data Submission(s)

8.2.1.3 Performance Metrics Identified by the Electrical Corporation

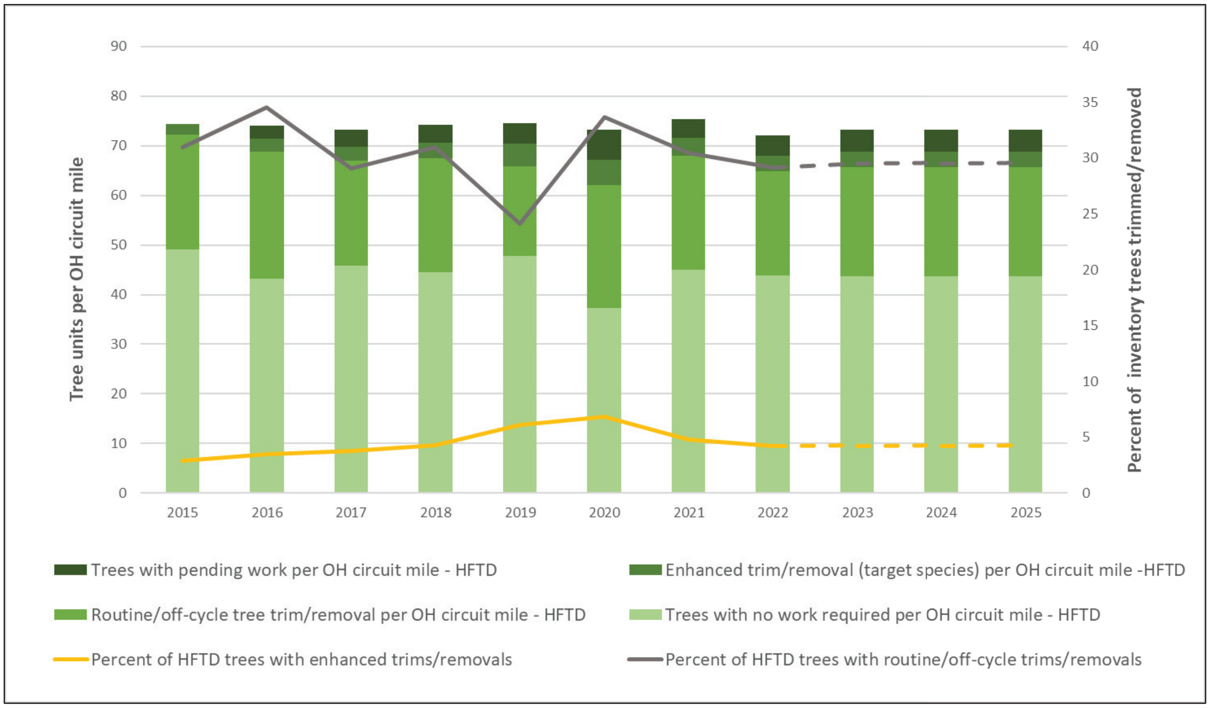
OEIS Table 8-16: Vegetation Management and Inspection Performance Metrics Results by Year

Performance Metrics	2020	2021	2022	2023 Projected	2024 Projected	2025 Projected	Method of Verification
Vegetation outages in the service territory per 1000 OCM	4.73	6.35	4.9	5.02	5.02	5.02	QDR
Vegetation outages in HFTD per 1000 OCM	1.73	2.61	4.35	2.74	2.74	2.74	QDR
Vegetation ignitions in the HFTD per 1000 OCM -Distribution	0	0	0.29	0.06	0.06	0.06	QDR
Trees with pending work per OCM - HFTD	3.37	2.44	4.15	3.55	3.55	3.55	QDR
Enhanced trim/removal (target species) per OCM -HFTD	5.03	3.64	3.04	3.19	3.19	3.19	QDR

8.2.1.3.1 Vegetation Inspections and Clearance in the HFTD

The number of inventory trees (trees that can impact the electric system) within the service territory can vary from year to year but averages around 485,000 trees each year and roughly 255,000 in the HFTD. As shown in Figure 8-27, this averages approximately 74 trees per circuit mile within the HFTD and has stayed consistent over the past 8 years. Each year, an average of 30 percent of inventory trees within the HFTD are trimmed or removed and approximately 5 percent receive enhanced trimming or removal beyond the minimum 12-foot clearance. The Enhanced Vegetation Management program (WMP.501) was formally introduced in 2019 to target additional clearances on tree species that posed an additional threat to powerlines. As SDG&E has inspected each of these targeted species for enhanced clearances each year, the number of trees that require enhanced trimming has decreased slightly in 2021 and 2022. SDG&E will continue to investigate this trend as the number of trees that require enhanced clearances can be impacted by many factors. Overall, vegetation management activities are part of a mature program and are expected to remain relatively constant over the next WMP period.

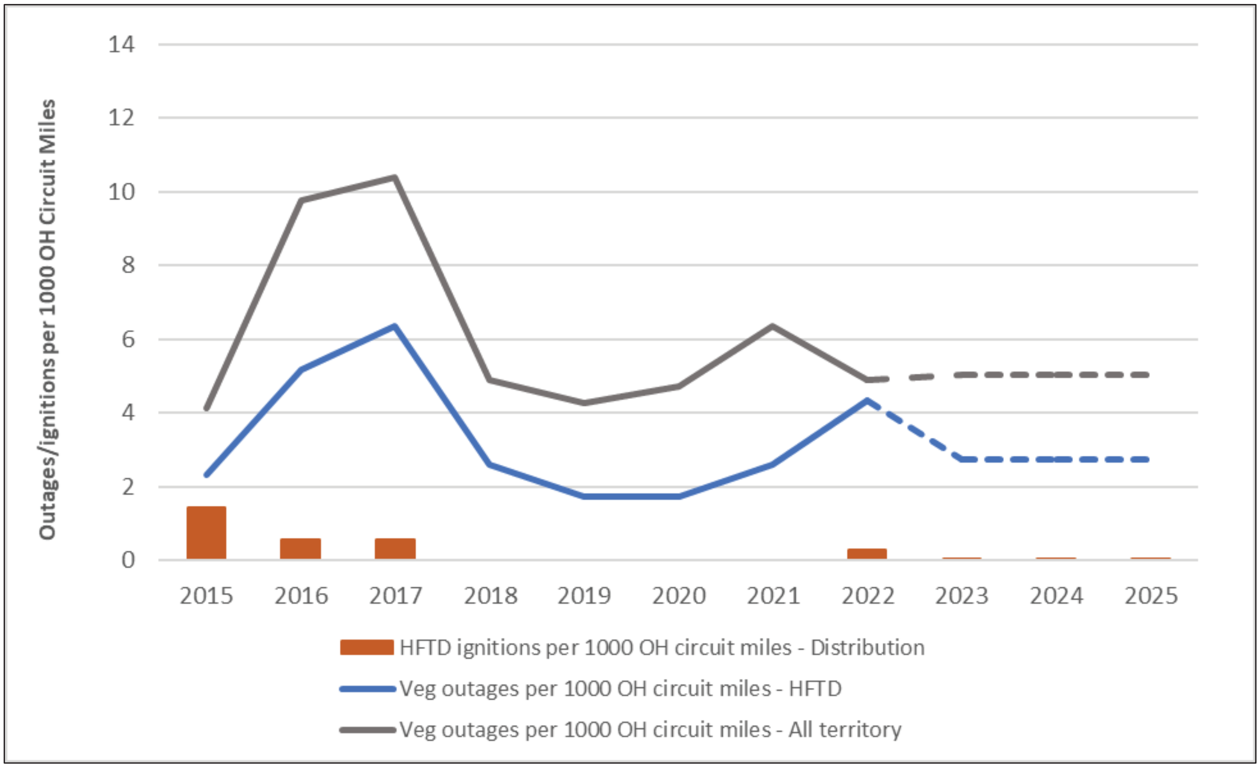
Figure 8-27: Vegetation Inspections and Clearance in the HFTD



8.2.1.3.2 Vegetation Outages and Ignitions in the HFTD

Vegetation-related risk events and ignitions remain a relatively low percentage of overall events. As shown in Figure 8-28, vegetation-related outages represent less than 3 percent of all overhead primary distribution outages. Additional work on vegetation management within the HFTD has produced positive results as the system saw an average of 4.6 vegetation-related outages within the HFTD between 2015 and 2017 and 2.6 between 2018 and 2022. Similarly, ignitions associated with vegetation-related events have decreased with only one ignition on the primary distribution system between 2018 and 2022 for an average of 0.2 ignitions per year as compared to 2015 to 2017 which saw an average of three ignitions per year. SDG&E’s projections for these events moving forward are aligned with the 5-year average and are expected to remain relatively stable.

Figure 8-28: Vegetation Outages and Ignitions in the HFTD



8.2.2 Vegetation Inspections

OEIS Table 8-17: Vegetation Management Inspection Frequency, Method, and Criteria

Type	Inspection Program	Frequency or Trigger	Method of Inspection	Governing Standards & Operating Procedures
Transmission and Distribution	Detailed Vegetation Inspections (WMP.494)	Annual; in HFTD twice-annual	Ground inspection; helicopter inspection	GO 95, Rule 35; PRC § 4293; NERC FAC-003-4
Transmission and Distribution	Off-Cycle HFTD Patrols (WMP.508)	Annual; in HFTD twice-annual	Ground inspection	GO 95, Rule 35; PRC § 4293; NERC FAC-003-4
Transmission	Substation (see Section 8.1.3.11)	Monthly/bi-monthly	Ground inspections	GO 174

8.2.2.1 Detailed Vegetation Inspections (WMP.494)

Vegetation management operations are driven by regulatory requirements and follow an annual, master schedule that includes pre-inspection, tree trimming, auditing, and pole brushing (WMP.512). During the annually scheduled routine inspection activity, all inventory trees are inspected to determine whether they require pruning for the annual cycle. Information for each inventory tree is recorded within the electronic inventory tree database, PowerWorkz.

Inspection[30] activities are performed conjointly for distribution and transmission facilities. Vegetation Management does not perform vegetation inspection or maintenance activities within substation facilities. Vegetation Management responsibilities for maintenance begin in the portion of the first span located outside the fenced perimeter of substation facilities. Vegetation inspection and maintenance within the perimeter of a substation must be performed by QEWs. This activity is performed by Kearny Maintenance and Operations. Vegetation maintenance within the physical perimeter of substation fencing and immediately adjacent to the outside the perimeter of substation fencing is performed by SDG&E's Real Estate, Facilities, & Land Services Department.

There are two levels of vegetation management inspections:

- Level 1 inspection is a cursory assessment of trees within the right-of-way to determine which require pruning for the annual cycle based on tree growth and/or to abate a hazardous condition.
- Level 2 inspection is a 360-degree visual assessment of a tree where the crown, trunk, canopy, and above-ground roots are evaluated for specific hazards to the electric infrastructure. This may also involve simple tools such as a mallet to sound the tree trunk.

Detailed vegetation inspections (WMP.494) follow an annual, static Master Schedule of activities. Activities are scheduled and performed using a system of geographic VMA. The service territory is comprised of 133 VMAs. Each VMA may consist of several distribution circuits and transmission lines, and each may include several thousand inventory trees and hundreds of brushed poles.

Ten to twelve VMAs are pre-inspected each month within the Master Schedule such that all 133 VMAs are completed each year. During the detailed inspection activity, all trees within and adjacent to the distribution and transmission right-of-way are assessed to determine whether tree trimming or removal is required for the annual cycle. Within the HFTD, all trees in the utility strike zone are assessed for tree growth and hazard potential, including a 360-degree, Level-2 inspection of the trees from the ground to the canopy. A Level-2 inspection includes an overall visual inspection of the tree's health including the root zone, trunk, and branches, and may entail sounding of the tree for structural integrity.

8.2.2.1.1 Process

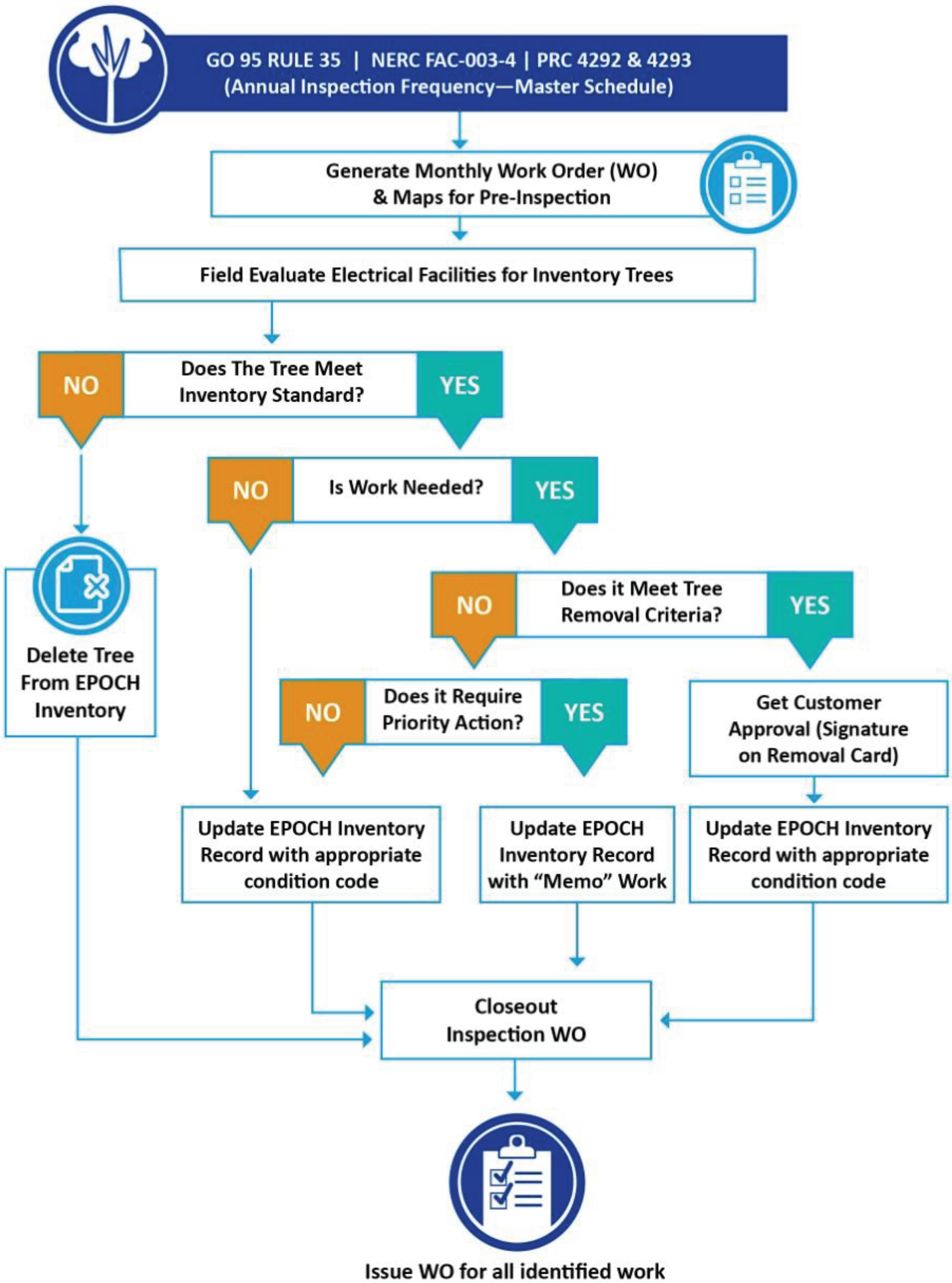
During the detailed vegetation inspection activity (WMP.494), the pre-inspector determines which trees in the landscape meet SDG&E's criteria for an inventory tree: a tree that may encroach within the minimum clearance requirements by growth or that may otherwise pose a threat to the overhead facilities due to trunk or branch failure within 3 years of inspection. Inventory trees are managed and tracked within PowerWorkz. Each inventory is assigned a unique, alpha-numeric identification and is represented in the system as an electronic tree record. The tree record includes a rich data set of information including tree species, height, DBH, GPS location, clearance, general tree health, tree work status, activity history, and customer information. Each inventory tree record within a VMA is updated during the detailed inspection activity.

During routine pre-inspection within the HFTD, all trees within the strike zone of transmission and distribution lines receive a Level 2 hazard evaluation. Trees tall enough to strike overhead electric lines

[30] These may also be referred to as "pre-inspection" activities. Pre-inspection is a commonly used term to denote inspection activities that occur prior to tree trimming.

are assessed for trimming or removal and include identification of dead, dying, and diseased trees, live trees with a structural defect, and conditions such as wind sway and line sag. The visual inspection includes a 360-degree hazard assessment of trees from ground level to canopy height to determine tree health, structural integrity, and environmental conditions. Where appropriate, sounding techniques or root examination may also be conducted. Where required, trees are trimmed or removed to prevent line-strike from either whole tree failure or limb break out. Figure 8-29 shows the inspection process.

Figure 8-29: Detailed Vegetation Inspections Process Flow



8.2.2.1.2 Frequency or Triggers

Detailed vegetation inspections (WMP.494) are performed annually throughout the service territory following the static Master Schedule. Detailed vegetation inspection frequency is driven primarily by the regulatory requirements of GO 95, Rule 35; PRC § 4293; and NERC FAC-003-4. Within the HFTD, tree inspections are performed twice annually. The second, incremental HFTD inspection activity is described in Section 8.2.2.2 Off-Cycle Patrol Inspections. Species-specific risk-based vegetation inspections are performed annually including Century Plant and Bamboo. These inspection activities are performed throughout the service territory. Century Plant and Bamboo inspection activities are described in Section 8.2.2.2.2. During the post-trim QA/QC audit activity (WMP.505), an audit contractor performs a cursory vegetation inspection of all overhead lines within each VMA. This activity occurs 6 to 8 months following the routine scheduled detailed inspection activity and serves as a “mid-cycle” patrol to ensure vegetation does not pose a compliance or safety risk to the lines prior to the next inspection activity.

Risk prioritization is incorporated in scheduling detailed vegetation inspection activities. Following the annual Master Schedule, routine tree trimming activities occur 2 to 4 months after the inspection activity for a given VMA. For example, VMAs whose routine inspection occurs in January are subsequently trimmed during the months of March and April. During the routine inspection activity, if a tree is found to be near the power lines or exhibits an elevated hazardous threat, the tree will be treated as a “Memo” and issued to the tree trim contractor to work on a priority basis. A Memo tree can be prioritized as a same-day trim or up to two weeks to complete depending on the conditions.

8.2.2.1.3 Accomplishments, Roadblocks, and Updates

Enhancements and progress made since the last WMP submission include:

- Implemented multiple update releases to Epoch. Enhancements included software updates, addition of tree Genus/species attribute field, and new electronic mapping imagery to enhance field navigation and data accuracy.
- Integrated Vegetation Risk Index (VRI) GIS mapping layer into Epoch mobile application for user situational awareness during inspections.
- Engaged with a third party to study the correlation between enhanced tree trim clearances and reduction of vegetation-caused outages.
- SDG&E, PG&E, and SCE began collaboration on a vegetation clearance study to determine the effectiveness of expanded trim clearances on risk-event frequency (see response to Areas for Continued Improvement 22-21 in Appendix D).
- Continued engagement with the Electric Power Research Institute, Inc (EPRI) to study the relationship between expanded clearances and reduction in tree-related outages. For more information see response to Areas for Continued Improvement SDGE 22-09 in Appendix D.
- Hired four internal Forester Patroller positions to perform off-cycle tree inspections within the HFTD.

Roadblocks the electric corporation has encountered:

- Concurrence from land agencies such as California State Parks and U.S. Forest Service on SDG&E’s implementation of enhanced vegetation management clearances including the mitigation of perceived hazards outside utility rights-of-ways remained a challenge. SDG&E met with California State Parks and Forest Service to discuss enhanced Vegetation Management activities and reached consensus on work scope that achieves SDG&E's risk mitigation strategies while ensuring environmental and resource protection requirements.

Changes/updates to the inspection including known plans the electric corporation may implement in the next 5 years:

- Further integrate and operationalize land-based (vehicle and personnel) LiDAR, satellite imagery technology, and risk analyses into detailed inspection activities and decision-making
- Continue to collaborate with joint IOUs on multi-year vegetation management enhanced clearance study, and hazard tree inspection best management practices
- Further integrate VRI into inspection activities for the HFTD
- Further engage third-party study on risk modeling at the tree asset and span level
- Continue eradication program of Century plants within transmission corridors through biological means (herbicide use).
- Began a strategic sourcing effort in 2022 to go out to bid for all Vegetation Management contracts in 2023 with the option to extend service agreements up to 7 years which will provide better long-term planning, stability, and resource management with vendors.

8.2.2.2 Off-Cycle Patrol Inspections (WMP.508)

Vegetation Management performs a second annual tree inspection activity within the HFTD referred to as the "off-cycle" patrol (WMP.508). Of the 133 VMAs in the service territory, 106 are either partially or wholly within the HFTD. Approximately 240,000 of the 485,000 inventory trees are located within the HFTD.

In addition to the off-cycle HFTD patrol, additional annual inspections are performed for Century Plant and Bamboo due to their fast and unpredictable growth. Century Plants (Agave) have a flowering stage at the end of their lifecycle that includes the growth of an elongated, vertical flower stalk. Upon emerging, the stalk can grow to the height of power lines in weeks and may pose an ignition threat. Bamboo are fast-growing species that are difficult to manage for line clearance within a single annual trim cycle. Additional inspections of Century Plant and Bamboo have proven effective in intercepting the growth of these species and preventing contact and potential ignition.

8.2.2.2.1 Process

The scope of the off-cycle HFTD patrol (WMP.508) is similar to the routine, detailed vegetation inspection activity in the HFTD. During the off-cycle HFTD patrol all trees within the strike zone of the secondary, distribution, and transmission lines receive a Level 2 hazard evaluation. Trees tall enough to strike overhead electric lines are assessed for trimming or removal and include identification of dead, dying, and diseased trees, live trees with a structural defect, and conditions such as wind sway and line sag. The visual inspection includes a 360-degree hazard assessment of trees from ground level to canopy height to determine tree health, structural integrity, and environmental conditions. Where appropriate, sounding techniques or root examination may also be conducted. The off-cycle patrol is performed by internal Patrollers and by contractors who are International Society of Arboriculture (ISA)-Certified Arborists. Certified Arborists specialize in hazard tree assessment, and all who perform off-cycle patrols receive annual hazard tree refresher training. The off-cycle patrol process is the same as detailed vegetation inspections, see Section 8.2.2.1 Detailed Vegetation Inspections for details.

8.2.2.2.2 Frequency or Triggers

The off-cycle patrol (WMP.508) represents the second annual inspection activity within the HFTD. Frequency is driven primarily by the regulatory requirements of GO 95, Rule 35; PRC § 4293; and NERC FAC-003-4. The off-cycle activity is based on the Vegetation Management Master Schedule. Any priority tree work identified during the off-cycle HFTD patrol is expedited as needed via the "Memo" process to mitigate the risk. Memos are completed the day a condition is observed or up to two weeks following depending on the situation's priority.

In 2022, the schedule and timing of the annual off-cycle HFTD patrol was modified. Prior to 2022, the annual off-cycle HFTD patrol was performed as an approximate mid-cycle inspection for each HFTD VMA. The activity occurs approximately six months following the routine inspection schedule of each HFTD VMA. In 2022, the schedule was modified to perform the off-cycle patrol in all 106 HFTD VMAs within the three-month quarter immediately preceding September, which is the onset of the Santa Ana Wind season in Southern California. The goal was to condense all off cycle HFTD inspections closer to the end of September.

In early 2022, a third-party vendor was engaged to conduct an efficacy study of the off-cycle HFTD patrol schedule to determine the optimum schedule based on historical tree risk within each HFTD VMA. Historical tree risk was measured by looking at the frequency of trees that have required a priority "Memo" trim, and/or were identified as a hazard tree. The study also considered increasing the 3-month off-cycle HFTD schedule to an 8-month schedule (January to August) and prioritizing the patrol activity for the riskiest VMAs closer to the month of September. This risk-based approach generates a machine learning model that scores trees based on descriptive features, historical growth patterns, and historical priority "Memo" trims. The model uses this data as features and produces a predicted score for the next cycle year. This predicted score is then used to help understand the tree's likelihood of needing a priority "Memo" trim. To understand the growth risk at a higher level for operational purposes, scores are aggregated to each VMA. VMAs can then be ranked, which helps determine which ones may need the most attention. The VMA ranking provides input for generating the off-cycle HFTD schedule, which evenly distributes labor across the first 8 months of the year, provides time between the detailed and off-cycle inspections, and places the riskiest areas to be inspected closest to fire season.

For targeted species patrols, a second, annual inspection is performed for every inventory Century plant within the service territory. An additional annual inspection is performed for this species due to their fast and unpredictable growth. Century Plants (Agave) have a flowering stage at the end of their lifecycle that includes the growth of an elongated, vertical flower stalk. The stalk can grow to the height of power lines in weeks and may pose an ignition threat. The Century Plant patrol is scheduled in the spring each year when Century Plants typically bloom. Any plant with an emerging flower stalk is topped to prevent further encroachment into the power lines, and to prevent contact with the lines when the plant dies and the stalk falls.

The targeted species patrols for Bamboo are scheduled in the summer and fall each year. During these activities, every Bamboo in the Vegetation Management tree inventory database is inspected for growth. These patrols are in addition to the routine detailed inspection that occurs within each VMA's scheduled month. Therefore, in essence, each inventory bamboo is inspected three times each year.

The additional inspection activities for Century Plant and Bamboo have proven effective in intercepting the growth of these species and preventing contact and potential ignition.

8.2.2.2.3 Accomplishments, Roadblocks, and Updates

Enhancements and progress made since the last WMP submission include:

- Engaged third-party study of off-cycle HFTD schedule (WMP.508) to determine optimum timeframe and prioritization of inspection activities based on risk metrics within each VMA Level.
- Modified the schedule of the off-cycle HFTD patrols in the VMAs to occur in Q3.
- Completed all scheduled, off-cycle HFTD patrols prior to September.
- Completed all targeted, additional Century Plant and Bamboo species patrol in 2022.
- Implemented multiple update releases to Epoch. Enhancements included software updates, addition of tree Genus/species attribute field, and new electronic mapping imagery to enhance field navigation and data accuracy.
- Created new electronic off-cycle, HFTD SWO in PowerWorkz to differentiate from routine inspection activity SWOs. Added ability to electronically map and record progression of inspection activities at the span level.
- Continued study with SDSC to develop risk modeling related to outage frequency and enhanced tree clearances.
- Completed redrawing of the VRI into new polygons based on the addition of several new pole-mounted weather stations, thus updating the associated risk to the circuit line segments.
- Continued additional inspection activities throughout 2022 as they have proven to be effective in mitigating the risk of outage, ignition, and wildfire.
- Engaged Patrollers to assist in the resolution of customer refusals while performing off-cycle patrols in the HFTD VMAs
- Proactively managed Century plants within transmission and distribution corridors through biological means (herbicide use). Approximately 610 Century plants were treated in 2022.

Roadblocks the electric corporation has encountered:

- Managing multiple Vegetation Management activity schedules within each VMA to avoid overlapping or redundant activities while ensuring data integrity. To do this, the off-cycle HFTD patrols were scheduled in some VMAs where the routine activity was concurrently scheduled to occur in the same month.
- Not having unique and specific HFTD SWO in the PowerWorkz work management system to differentiate from other Vegetation Management patrol activities. This issue was remediated in 2022 with the creation of new HFTD patrol SWOs which also allowed electronic mapping documentation of the patrols.
- Resource challenges with the number of SDG&E Patrollers to complete the off-cycle HFTD patrols. To overcome this, Pre-inspection and Auditing contractors were engaged to perform some of the off-cycle HFTD patrols.

Changes/updates to the inspection including known future plans the electric corporation may implement in the next 5 years:

- Continue to research and modify off-cycle HFTD schedule were necessary to optimize risk reduction.
- Identify proper resource need and allocation to perform the off-cycle HFTD inspection timely and efficiently.
- Identify additional and proactive HFTD inspection activity opportunities such as pre-PSPS and adverse weather condition and event patrols.
- Further integrate and operationalize risk and condition-based data such as meteorology and environmental conditions into ground-level decision-making.

8.2.3 Vegetation and Fuels Management (WMP.497)

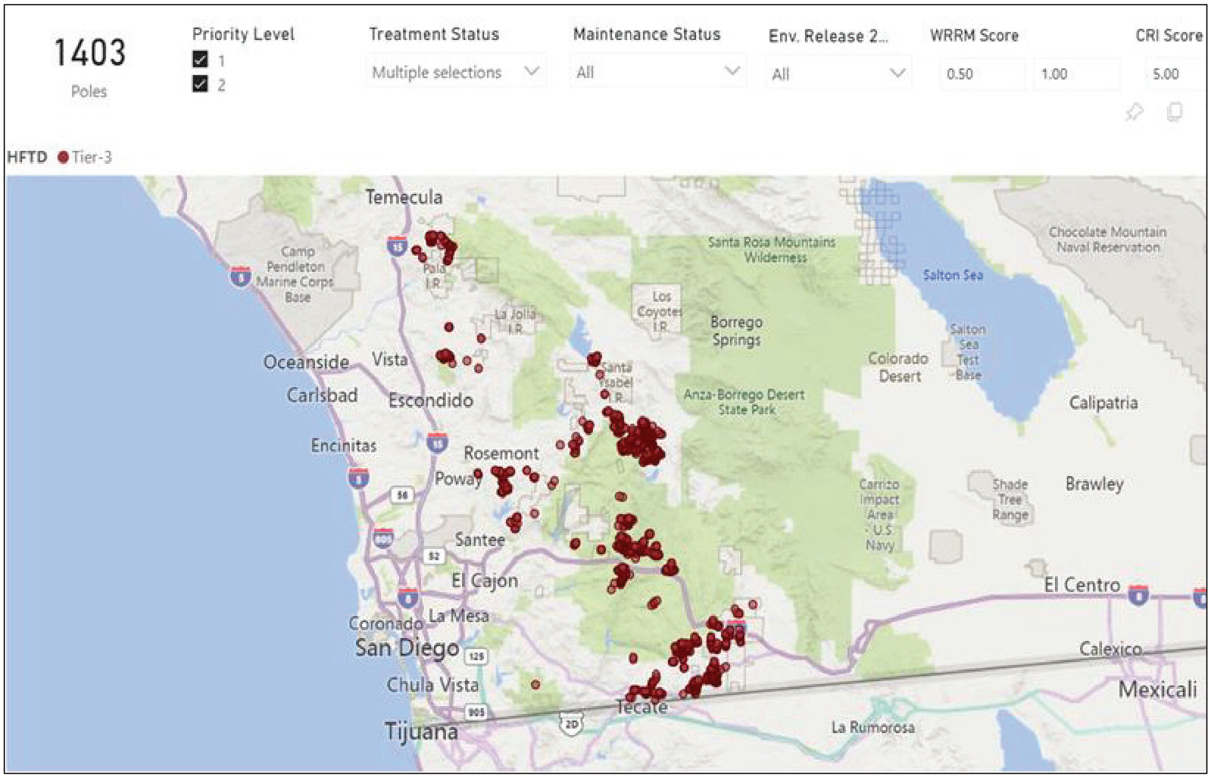
Vegetation Management Fuels Activity Treatment

The fuels activity treatment includes the thinning of ground vegetation surrounding structures located in the HFTD where the risk of ignition and propagation is present. Specifically, vegetation is thinned in a 50-foot radius from the outside circumference of the structures down to an approximate 30 percent vegetation cover where achievable. Non-native vegetation is prioritized for thinning. The activity is also intended to protect infrastructure in the event of a wildfire. Structures that are subject to the pole clearing (brushing) (WMP.512) requirements of PRC § 4292 are targeted for fuels activity treatment. These structures are prioritized because the risk of ignition is relatively higher due to the presence of hardware that makes them subject to pole clearing. See Section 8.2.3.1 Pole Clearing (WMP.512) for details regarding this activity.

Vegetation Management performs a risk analysis review to determine which poles will be treated under this program. The analysis includes the identification of structures where the fuels component may be conducive to ignition. Risk Assessment and Mapping (WMP.442) and WRRM are tools used to identify higher risk areas in the HFTD to prioritize and perform fuels modification activities (see Figure 8-30). Aerial imagery can also be a valuable tool to further refine targeted work locations. Work locations are also pre-screened for environmental impact to avoid negative impact to species.

The fuels activity treatment is a discretionary activity SDG&E believes is a prudent, additional fire prevention measure.

Figure 8-30: Fuels Modification Sites Using Risk Assessment and Mapping and WRRM



SDG&E sponsored a third-party study of its Fuels Treatment activities in 2022 to review the efficacy of the program and potential risk reduction. The relatively low frequency of utility ignitions provides limited data with which to provide definitive analysis of the effect of this program. SDG&E will continue to consider alternatives to its current Fuels Treatment (WMP.497) Program, however, SDG&E believes this is a prudent mitigation activity to further reduce the risk of ignitions. Additionally, analysis and feedback are received from the primary vendor who manages the initiative for feedback on process improvement, safety, work scope, planning/scheduling, customer engagement, environmental impact, and customer engagement. For details on the consideration of alternatives to fuels treatment activity, see response to Areas for Continued Improvement SDGE-22-21 in Appendix D.

Enhancements in 2023 will include:

- Fuels Treatment activity
    - Continue to assess cost/benefit and research alternatives such as fire retardants.
    - Engage third party to study the methodology and effectiveness of the fuels treatment activity.
    - Provide customer engagement and awareness earlier in the year to streamline authorization to perform.

8.2.3.1 Pole Clearing (WMP.512)

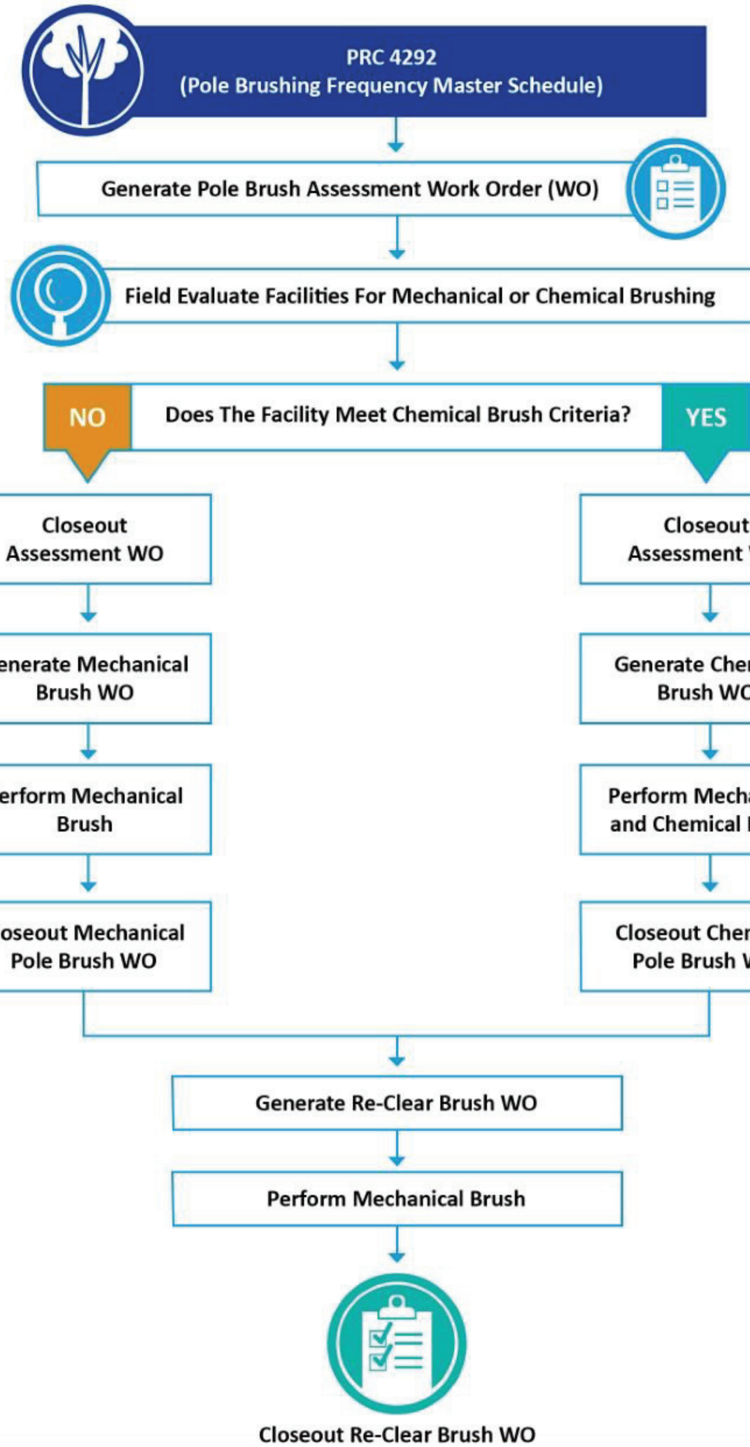
8.2.3.1.1 Utility Initiative Tracking ID

WMP.512

8.2.3.1.2 Overview of the Initiative

Pole clearing (WMP.512) is a fire prevention measure involving the removal of vegetation at the base of poles that carry specific types of electrical hardware that could cause sparking or molten material to fall to the ground. The clearance requirements in PRC § 4292 require the removal of all vegetation down to bare mineral soil within a 10-foot radius from the outer circumference of subject poles located within the boundary of the State Responsibility Area (SRA). The requirement also includes the removal of live vegetation up to 8 vertical feet and the removal of dead vegetation up to conductor level within the clearance cylinder. Figure 8-31 shows the process flow for pole clearing.

Figure 8-31: Pole Clearing (Brushing) Process Flow



8.2.3.1.3 Governing Standards and Electrical Corporation Standard Operating Procedures

Pole clearing (brushing) (WMP.512) is performed on approximately 34,000 poles located in the SRA of the service territory subject to PRC § 4292. PowerWorkz is utilized to manage and track the inventory of all subject poles that require clearing. Inspectors determine which poles require work and update the records in the database. Three separately scheduled pole brush activities are performed annually, including mechanical brushing, chemical application, and re-clearing. Pole brush inspection occurs in conjunction with tree inspection activity.

Mechanical pole brushing is the clearing all vegetation around the base of a pole down to bare mineral soil for a radius of 10 feet from the outer circumference of the pole; removing all live vegetation within the cylinder up to a height of 8 feet above ground; and removing all dead vegetation up to the height of the conductors. Mechanical brushing is typically performed in the spring months.

On poles where environmentally safe and with customer consent, contractors will apply an Environmental Protection Agency (EPA)-approved herbicide to suppress seed generation, limit vegetation re-growth, and reduce overall maintenance costs. The chemical application is typically done just before the rainy season (fall and winter), so the chemical is activated and effective.

Re-clearing is a second mechanical activity performed on poles that are not cleared by a chemical application. The need to revisit and clear a subject pole multiple times for compliance is not uncommon due to leaf litter cast, vegetation regrowth, or material that has blown into the clearance area which cannot be controlled by mechanical or herbicide treatments.

Pole clearing follows a specific annual, multi-activity schedule to remain compliant year-round. The number of subject poles fluctuates minimally year-to-year so scheduling, spend, and resource allocation remain constant. An environmental review is performed in advance of any new subject pole requiring brushing to assess impacts to protected species and habitat. Like all other vegetation management activities, a third-party QA/QC audit (WMP.505) is performed on a random, representative sample of all completed pole-brush work. See Section 8.2.5 for additional information on QA/QC.

8.2.3.1.4 Updates to the Initiative

The scope of the pole clearing initiative (WMP.512) has changed little since the last WMP submission. Vegetation Management continues to visually inspect every distribution and transmission pole located within the SRA in tandem with the annual, routine schedule pre-inspection activity to identify any new poles subject to PRC § 4292.

In 2022, Vegetation Management began an initiative with the Electric GIS business unit and the Asset Management business unit to proactively identify and communicate new construction activities where new subject hardware is installed on poles. This communication helps streamline the process of identifying new subject poles, reduces the timeframe for mitigation, helps to ensure compliance, and reduces the likelihood of an ignition. Vegetation Management also works closely with the ESH Program (WMP.453, WMP.459, WMP.464, WMP.550) in the use of drones to identify new subject hardware or non-compliant conditions in the HFTD. In the next 2 to 3 years Vegetation Management will work with these business units and initiatives to create automated notifications whenever a new subject pole is created within the SRA.

In addition to the approximately 34,000 poles SDG&E clears every year for compliance and fire prevention, approximately 2,475 poles are cleared in the Local Responsibility Area (LRA). This includes poles located in areas of dense and/or highly flammable vegetation and/or located near steep topography. This work exceeds the regulatory requirement of PRC § 4292. This work is performed as a prudent measure to further reduce the risk of ignition and propagation from one of its poles resulting from molten ejecta.

8.2.3.2 Wood and Slash Management (WMP.497)

8.2.3.2.1 Utility Initiative Tracking ID

WMP.497

8.2.3.2.2 Overview of the Initiative

Wood and slash management (WMP.497) are a component of tree trimming and removal operations. Most of the wood and slash debris resulting from routine trimming and removal activities are chipped on site and removed from the property the same day the work is performed. Large wood debris (generally greater than 6 inches diameter) is cut into manageable lengths and left on site. Where requested, all wood debris and wood chips may be left on a landowner’s property for customer utilization. Figure 8-31 shows the process flow for pole brushing (WMP.512), which includes wood and slash management.

Vegetation debris (i.e., slash) generated from fuels management and vegetation management activities are typically removed from the project site unless it is determined that a portion of the debris can be used on site for soil cover or other purposes. This determination is made upon review by Environmental Services. Property owners may also request that debris be left on sight as chipped material for ground cover or landscaping.

8.2.3.2.3 Governing Standards and Electrical Corporation Standard Operating Procedures

All debris associated with tree operations is removed from the channel and banks of watercourses (rivers, streams, lakes, wetlands, etc.) in accordance with environmental regulations such as California Department of Fish and Wildlife section 1600 (Fish and Game Code); California Department of Fish and Wildlife Lake and Streambed Alteration Program; and California Forest Best Practice Rules.

Unlike other areas of California that have experienced mortality in millions of trees because of continued drought and large-scale fires in the last several years, SDG&E has not experienced a high-volume tree mortality rate or a high-volume of wood and slash requiring movement and processing.

8.2.3.2.4 Updates to the Initiative

Wood and slash associated with tree operations is taken to one of several landfills located in San Diego County or to a wood recycling facility. As part of its larger sustainability initiative, SDG&E continues to increase the amount of its wood and slash material that is diverted to a recycling facility. Currently, approximately 55 percent of total wood debris is diverted to a recycling facility to be rendered into composting or other environmentally sustainable materials.

8.2.3.3 Clearance (WMP.501)

Trees are trimmed to clearances that meet or exceed the regulatory minimum clearances required in GO 95. The Enhanced Vegetation Management Program (WMP.501) continues to focus on applying expanded post-trim clearances on targeted species identified as higher risk due to growth potential, failure characteristics, and relative outage frequency. The criteria for determining post-trim clearances includes multiple factors such as species, height, growth rate, health, location of defect, site conditions, pruning schedule, and proper pruning cuts. The compliance goal is to trim to an appropriate clearance to prevent a tree from encroaching within the minimum clearance or contacting the power lines either by wind sway, branch breakout, or tree/root failure. The American National Standards Institute and International Society of Arboriculture standards are applied using the concept of directional pruning. If a tree cannot be mitigated by pruning, complete removal may be required. Emergency pruning may also occur when a tree requires immediate attention to clear an infraction or if it poses an imminent threat to the electric facilities.

Species are designated as “targeted” to facilitate the scope of the inspection activity. The genus or species is not a single determinant of whether an enhanced clearance and/or removal is warranted. Trim clearances are determined following a holistic assessment of tree-specific and site-specific conditions. Simply because a tree has been identified as requiring pruning or that the species is considered “target” does not mean it will require enhanced trim clearance.

8.2.3.3.1 Utility Initiative Tracking ID

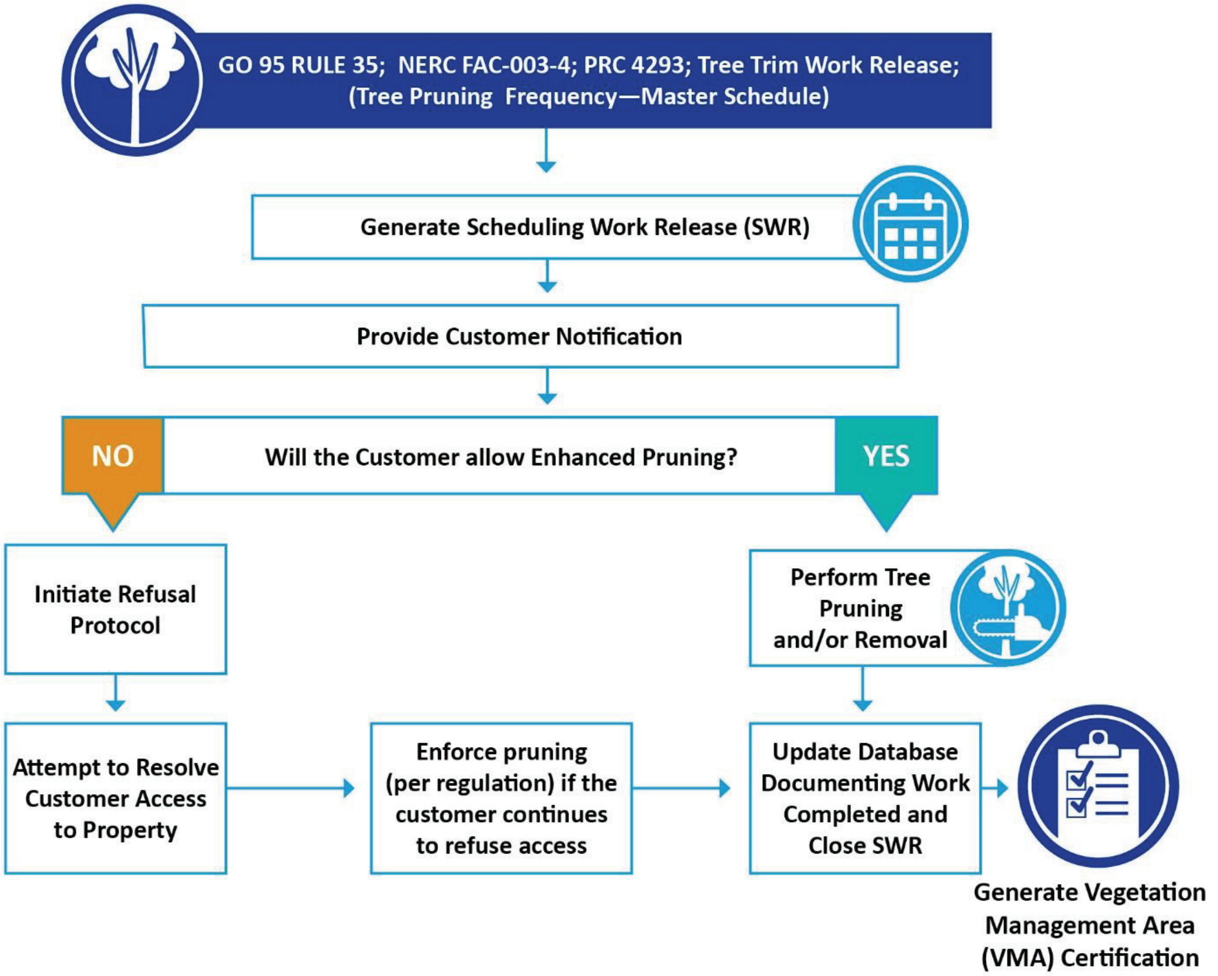
WMP.501

8.2.3.3.2 Overview of the Initiative

Vegetation Management defines enhanced clearances as greater than or equal to 12 feet at time of trim, which is the CPUC-recommended post-trim clearance for distribution voltages in the HFTD. Trees are trimmed to clearances that exceed the recommended time-of-trim clearances in GO 95. Certain species such as Eucalyptus, Sycamore, Palm, Oak, and Pine are considered higher risk and targeted for enhanced clearances due to a propensity to be difficult to manage because of their relative fast-growth, historical outage frequency, and/or propensity for branch failure. These tree species are generally associated with the significant majority of all vegetation-caused outages, particularly when measured against their overall percentage of SDG&E’s entire tree inventory.

Clearances of 20 to 25 feet or greater may be achieved where deemed necessary for safety, compliance, and reliability. The tree contractor determines the proper clearance for each tree at the time of trim. If a tree cannot be mitigated by pruning, complete removal may be necessary. Emergency pruning may also occur when a tree requires immediate attention to clear an infraction or if it poses an imminent threat to the electric facilities. SDG&E will continue pursuing expanded trim clearances greater than 12 feet in HFTD for targeted species, exceeding regulatory requirements and plans to establish benchmarking for optimal tree removal activities based on species, growth rate, tree density, risk. Figure 8-32 shows the process flow for enhanced clearance.

Figure 8-32: Enhanced Clearance Process Flow



SDG&E has collaborated with Energy Safety and other large California IOUs to continue studying the effectiveness of enhanced clearances. See response to Area of Improvement SDGE-22-20 in Appendix D.

Energy Safety expressed the need and is planning to hold initial and on-going meetings with the joint-IOUs and industry experts to identify vegetation best management practices for wildfire risk reduction. SDG&E will participate in future Energy-led scoping meetings and has recommended and provided contact names of industry experts who may assist in this initiative. For details on best management practices scoping meeting, see response to Areas for Continued Improvement SDGE-22-22 in Appendix D.

8.2.3.3.3 Governing Standards and Electrical Corporation Standard Operating Procedures

The governing standards for clearance include GO 95, Rule 35; PRC § 4293, and NERC FAC-003-4.

8.2.3.3.4 Updates to the Initiative

There is a high degree of variability in forecasting the number of trees that may require enhanced trimming, including but not limited to: species, precipitation, tree growth, location of defect, pruning frequency, and regional tree mortality. The methodology to derive the target for this initiative was modified in 2022 using tree inventory trim frequency data and historical averages. However, since the enhanced trim/removal initiative is relatively new (beginning in 2019), the data is still somewhat limited for forecasting using a trend analysis with a high degree of confidence. Using current trends, it is likely a more accurate forecast number of trees that will require enhanced clearance annually is 10,000 to 11,000. As more data becomes available, the methodology will be reviewed in order to derive an appropriate, annual target for this initiative.

8.2.3.4 Fall-in Mitigation (WMP.494)

8.2.3.4.1 Utility Initiative Tracking ID

WMP.494

8.2.3.4.2 Overview of the Initiative

The Fall-in Mitigation initiative (WMP.494) is integrated within the detailed vegetation and off-cycle patrol inspection (WMP.508) initiatives that target problematic species such as Eucalyptus, Palms, Century plant, Bamboo, certain species of Pine, Oak, and Sycamore, before they become a danger. ISA Certified Arborists trained in hazard tree evaluation perform these inspections, which include a critical look at any tree that could strike the power lines. The utility tree strike zone is defined as the area where a tree is tall enough to hit the power lines if it were to fail at ground level. During the off-cycle patrol, trees are visually inspected from the ground to the upper canopy in a 360-degree circumference. Fall-in mitigation is part of detailed vegetation inspections, see Section 8.2.2.1 Detailed Vegetation Inspections for details.

8.2.3.4.3 Governing Standards and Electrical Corporation Standard Operating Procedures

See Section 8.2.2.1 Detailed Vegetation Inspections.

8.2.3.4.4 Updates to the Initiative

See Section 8.2.2.1.3 Accomplishments, Roadblocks, and Updates~~Accomplishments, Roadblocks, and Updates~~ and Section 8.2.2.2.3 Accomplishments, Roadblocks, and Updates~~Accomplishments, Roadblocks, and Updates~~.

8.2.3.5 Substation Defensible Space

See Section 8.1.3.11 Substation Patrol Inspections (WMP.492) for information on actions taken to reduce the ignition probability and wildfire consequence due to contact with substation equipment.

8.2.3.6 High-Risk Species

Refer to Section 8.2.3.3 Clearance for information on reducing the ignition probability and wildfire consequence attributable to high-risk vegetation species.

Right Tree, Right Place (WMP.1325)

As part of its tree removal program and its “Right Tree, Right Place” initiative, and for safety and reliability, SDG&E continues to offer customers the incentive to remove incompatible trees growing near power lines and continues to provide replacement trees compatible to plant near power lines. As part of its overall sustainability initiative, SDG&E has a target goal to distribute 10,000 trees annually to customers, communities, and agencies to promote environmental health and mitigate the impacts of climate change.

Community Tree Rebate Program (WMP.1326)

The Community Tree Rebate Program will target underserved communities to promote the planting of trees where climate equity is compromised. The program will offer each applicant a rebate on the purchase of up to 5 trees, ranging from 1 to 15 gallons. This initiative will help promote environmental awareness, teach sustainable tree planting, improve climate, and encourage community involvement. The program will launch in Q1 2023 and will align with San Diego’s traditional planting season. An interactive customer portal will help educate customers about the program and guide their application process.

8.2.3.7 Fire-Resilient Right-of-Ways

Actions are taken to promote vegetation communities that are sustainable, fire-resilient, and compatible with the use of the land as an electrical corporation right-of-way.

Land Services Vegetation Abatement (WMP.1327)

Vegetation Abatement activity was implemented to maintain SDG&E-owned parcels in a fire-safe manner as required by various municipal compliance ordinances, Fire Marshal directives, and community safety expectations. This activity is intended to reduce the fuel loading from overgrown vegetation that may propagate a fire if an ignition were to occur and consists primarily of the removal of ground level, non-native flashy fuels and the thinning of tree branches (to 6 to 8 feet) above ground on SDG&E-owned properties and right-of-way corridors. Typically, the same properties are abated annually or on a frequency based on vegetation growth. Depending on conditions such as plant species and rainfall frequency, inspection activities may occur monthly or weekly and may change depending on the season. Brush abatement activities are planned and scheduled in late February/early March each year near the end of the normal rain season and before the flush spring growth occurs. Methods to sustainably address vegetation abatement are continually explored and implemented, including goat grazing along transmission corridors.

Fire Coordination Fuels Reduction MOU & Grant (WMP.1328)

SDG&E sponsors funding for memoranda of understandings (MOUs) and grants to external partners for the purpose of reducing fuels near electrical infrastructure and to enhance community wildfire prevention and safety. The Fuels Reduction MOU & Grant activity targets electric right of ways, evacuation routes, and community defensible space areas to reduce the risk of a fire of consequence and to strengthen community resiliency. Fuel reduction treatments can slow fire spread, assist in firefighting efforts, and reduce the impact of fires on a community. The Fuels Reduction MOU & Grant activity is a partnership with community organizations to help reduce the risk of catastrophic fire in their respective communities associated with electric infrastructure. The fuel reduction treatments follow industry best practice and target utility right of ways in high fire danger areas.

Enhancements in 2023 will include:

- Vegetation Abatement activity
    - Expand the acreage to be abated by goat grazing in sections of the Transmission corridors within Chula Vista, Oceanside, Escondido, and Harmony Grove.
- Fuels Reduction Grant activity
    - Treatment of wildland fuels in proximity to electric facilities will be completed.

8.2.3.8 Emergency Response Vegetation Management (WMP.496)

8.2.3.8.1 Utility Initiative Tracking ID

WMP.496

8.2.3.8.2 Overview of the Initiative

Vegetation Management's static, annual Master Schedule provides a consistent method for planning and managing activities. The system also enables the flexibility for emergency response to unplanned or unscheduled work before, during, and after events such as PSPS, RFW, adverse weather, or a wildfire.

Vegetation Management actively participates in multi-disciplinary emergency operations preparation activities and training sessions for emergency event response. SDG&E contractors receive daily notifications of current wildfire conditions as a measure of ongoing preparedness including a weather forecast, current FPI rating, and related information. In advance of a forecasted RFW or Santa Ana event, SDG&E will determine if additional vegetation management patrols are needed to assess tree conditions and/or where known imminent issues may exist. Vegetation Management also participated in SDG&E Emergency Operations training for improved situational awareness and resource coordination.

As a forecasted event approaches, tree crew resources are staged and coordinated for standby operations within SDG&E's Construction & Operation Centers (Districts) and are utilized for storm response and restoration activities. Vegetation Management contractors are kept informed during forecasted elevated or extreme weather events, allowing them time to relocate crews to safe locations or to cease work operations if required. Where emergency tree trimming is required during elevated wildfire conditions, additional firefighting resources may be engaged to provide support.

Vegetation Management inspection and tree trimming activities are integral during post-fire event response. After any fire event of significant size Vegetation Management conducts a hazard tree assessment within the fire perimeter to identify dead, burned, and structurally defective trees that may pose a future threat to the overhead conductors or that may be required to facilitate restoration activities. The scope of such patrols includes a visual inspection of all trees within the strike zone in the fire perimeter. Abatement activities include topping dead/defective trees that could strike the lines or felling a tree if deemed required for worker safety, facility, or environmental protection. Vegetation Management activities are generally halted during active fire suppression in the interest of safety. Fire behavior is unpredictable, and conditions change rapidly that could render initial vegetation management activities ineffective. SDG&E will, where deemed completely safe, engage in some pole brushing during active fire suppression activities if determined that it could serve to protect infrastructure such as poles.

See Detailed Vegetation Inspection process flow-8.2.2.1.

8.2.3.8.3 Governing Standards and Electrical Corporation Standard Operating Procedures

Vegetation Management follows the company wildfire plan in ESP 113.1. Regulatory requirements for minimum clearances between vegetation and electrical infrastructure include GO 95, Rule 35; PRC § 4293; and NERC FAC-003-4.

8.2.3.8.4 Updates to the Initiative

Vegetation Management was activated only a few instances in 2022 for storm or wildfire related events. SDG&E experienced one RFW day and zero PSPS events in 2022. Because of light event activity, there were no significant changes to this initiative. Vegetation Management did respond to the Border 32 Fire Incident which occurred on 8/31/22 in San Diego's backcountry. This fire burned approximately 4,500 acres. A post-fire tree hazard tree inspection activity was performed after this event for facility restoration and future protection.

8.2.4 Vegetation Management Enterprise System (WMP.511)

8.2.4.1 Vegetation Inventory and Condition Database(s)

Vegetation Management utilizes the software system PowerWorkz to inventory vegetation and manage inspections. This work management system uses the CityWorks software platform and is the server side where SWOs and DWOs are created and submitted. The mobile application called Epoch is the mapping interface contractors use for data entry to record completed work. Epoch includes GIS layers, electric infrastructure, land ownership, and parcel information, and houses the electronic records for all tree and pole brushing assets.

8.2.4.2 Internal Documentation of the Database(s)

CityWorks and PowerWorkz data is stored in an Oracle database on an SDG&E server.

Vegetation Management and Pole Brushing (WMP.512) share the same PowerWorkz database, however there are separate tables within PowerWorkz between Vegetation Management (Tree Activity) and Pole Brushing (Pole Activity).

CityWorks is an off-the-shelf application by Trimble (formerly Azteca).

8.2.4.3 Integration with Systems in Other Lines of Business

Vegetation Management inventory, work activity, and asset history is stored within PowerWorkz. Other systems integrated with PowerWorkz include GIS, Epoch Mobile, and CityWorks.

GIS provides a comprehensive inventory of the electric transmission and distribution network assets maintained in an Oracle database. Epoch Mobile is utilized to collect data from the field and uploaded to PowerWorkz. CityWorks is used to schedule work orders for vegetation inspections, audits, and tree work.

8.2.4.4 Integration with the Auditing System(s)

The vegetation inspection data in PowerWorkz is used to create the audit sample, track results, and any related corrective actions. See Section 8.2.5 for more detailed information on the QA/QC program (WMP.505).

8.2.4.5 Internal Processes for Updating the System and Planned Updates

Change requests for CityWorks and PowerWorkz are managed through the standard IT change management methodology using a SIR. Issues are managed through ServiceNow ticketing system. A CAB reviews proposed changes each week. SDG&E plans to integrate additional situational awareness attributes within tree records in the CityWorks database and create new work order capabilities in PowerWorkz for specialized patrols.

System changes are developed in QA (Development Environment) for all updated processes. Once User Acceptance Testing is completed successfully, the updated system is deployed to the production environment.

SDG&E plans to move towards completing design and development of Epoch to enhance data management performance and move all existing tree inventory data to the Cloud.

8.2.4.6 Changes Since the Last WMP Submission

- The addition of new Genus and species attribute fields which enable improved identification granularity within the tree records
- Additional new map layers and updated photo imagery within Epoch for improved situational awareness and field planning
- New SWOs specific to the off-cycle HFTD patrol (WMP.508) activity for better planning, documentation, and reporting
- New mapping capabilities to electronically track and document inspection progression
- New data fields to electronically record customer refusals and other deferred work which negates the need for hard copy forms
- Creation of a refusal/deferred work dashboard to track and manage time-sensitive tree work

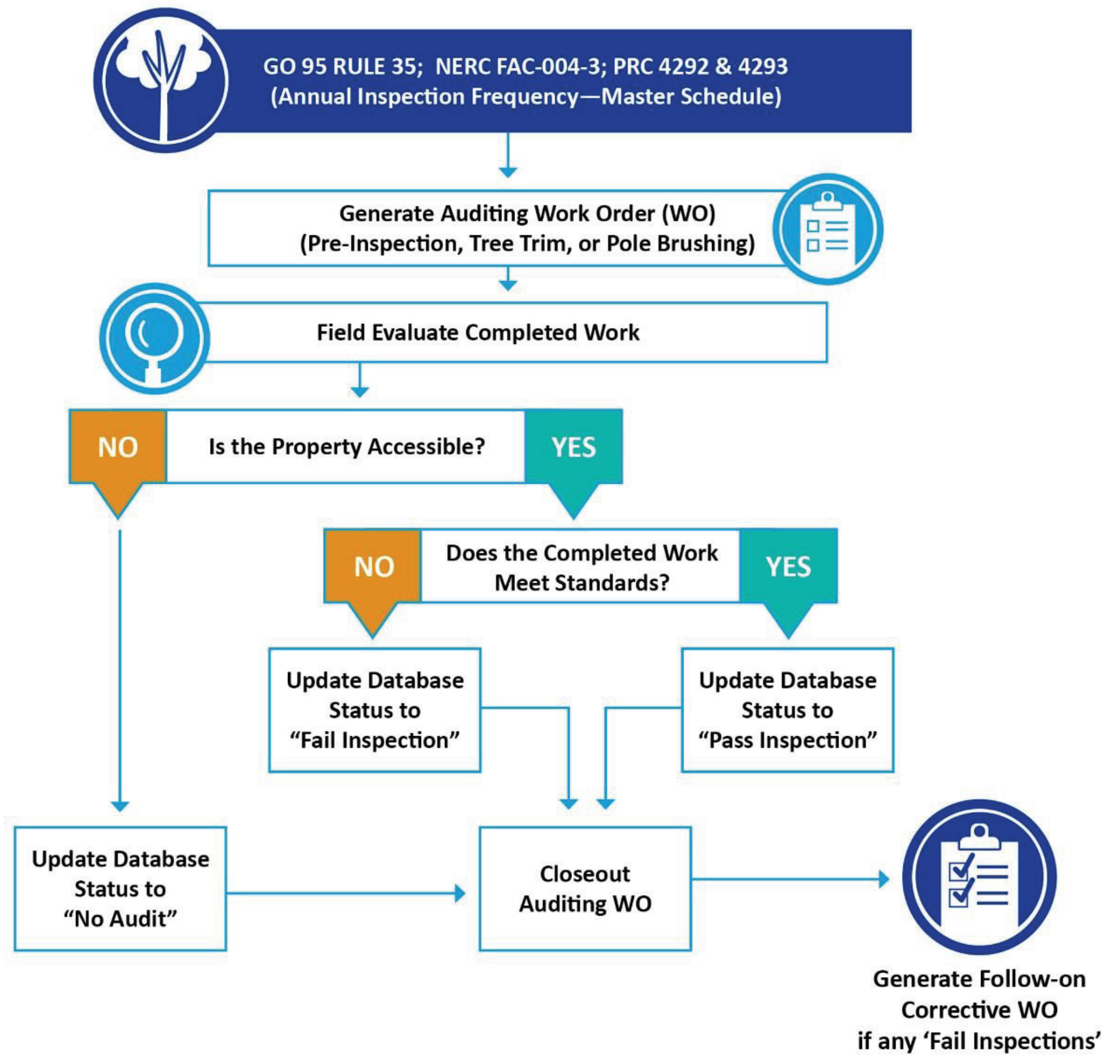
8.2.5 Quality Assurance / Quality Control (QA/QC)

8.2.5.1 QA/QC Procedure/Program (WMP.505)

SDG&E uses statistical sampling methodology in its audits of all Vegetation Management-related activities including pre-inspection, clearance (tree trimming), and pole clearing. Audit results are tracked, documented, and reported as a core component of contractor performance.

The QA/QC Program (WMP.505) includes additional scoping during some activities. In conjunction with the routine post-trim audit activity within a VMA, an additional tree inspection of all lines is performed to identify any trees that will not hold compliance until the next routine pre-inspection activity. Figure 8-33 shows the process flow for Auditing Pre-Inspection, Tree Trim, and Pole Clearing.

Figure 8-33: Auditing Pre-Inspection, Tree Trim, and Pole Clearing Process Flow



8.2.5.2 Sample Size

SDG&E uses a randomized, representative sample of all completed vegetation management work for the purposes of auditing. A sampling of 12 to 15 percent is used for all activities. Randomization of post-trim audit samples include representation of multiple tree crews. A higher sampling percentage is used for some enhanced vegetation management activities in the HFTD, including a 100 percent post-trim audit of all completed trim and removal work generated from the off-cycle patrol (WMP.508) activities. This target may not be achieved in some instances due to inaccessibility of work locations and/or customer refusals. Additionally, audits are performed on 100 percent of all work completed on tree trim "Memo" work orders.

8.2.5.3 Who Performs QA/QC

SDG&E contracts with a third-party to perform quality assurance audits of its vegetation management activities. Auditing is the sole activity function of this team.

8.2.5.4 Auditor Qualifications

Auditors include individuals who have a degree and/or experience in a field related to vegetation management, natural resources, environmental science, or biology. The auditors are mostly comprised of ISA Certified Arborists or those in the process of becoming certified. Most auditors have prior experience and position as a pre-inspector or tree trimmer and are trained and versed in utility vegetation management regulations, procedures, and field auditing.

8.2.5.5 QA/QC Findings and Incorporation of Lessons Learned

Audit findings are tracked within PowerWorkz. All audit activities are generated and submitted as work orders. Audit findings are documented within the individual electronic asset records and are available for reporting. Findings and observations are shared with contractors who are audited and reviewed for status, trends, and follow-up action. Audit fails for tree trimming and pole brush (WMP.512) activities are issued back to the contractor for corrective action.

OEIS Table 8-18: Vegetation Management QA/QC Program

Inspection Program	Sample Size	Type of Audit	Audit Results 2022	Yearly Target Pass Rate for 2023-2025
Pre-Inspection	12-15%	Field	94%	95%
Tree Trimming	12-15%	Field	99%	95%
Pole Clearing	12-15%	Field	97%	95%

8.2.5.6 Process Changes Since the Last WMP Submission

A 100-percent audit of all completed tree trimming and removal work generated during the off-cycle, HFTD patrol activity was performed where feasible. SDG&E is considering the development of compliance-based audits as a measure of system status and reliability. Such audits may be performed across multiple VMAs and create benchmarking for the performance of vegetation management operations. The anticipated timeline to implement compliance-based audits is 2 to 3 years.

8.2.6 Open Work Orders (WMP.1329)

8.2.6.1 Work Order Procedures

Vegetation Management activities are performed within electronic work orders assigned to contractors to track and document completed field work. Within PowerWorkz, a unique SWO is created annually for each activity (Inspection WMP.494, Tree Trimming WMP.501, Pole Brushing WMP.512, and Auditing WMP.505) in each VMA. Multiple DWOs are created by the contractors under the assigned parent SWO and distributed to the workers in the field. Upon completion of the field activity, asset records within the DWO are electronically coded as complete. Once all the assets within a DWO are complete, the

DWO status is completed. When all DWOs within the parent SWO are completed, the SWO status is completed.

8.2.6.2 Work Order Prioritization

Priority work may be processed using a “Memo” work order. A memo is an asset (tree or pole brush) that is either in a non-compliant condition or that otherwise requires priority action to mitigate the condition. “Memo” work orders are ad-hoc and external to the electronic tracking of a SWO and DWO. “Memo” work orders can be created and assigned to the respective contractor to complete the same day the condition is observed or within 30 days as deemed necessary by the inspector.

8.2.6.3 Work Order Backlogs

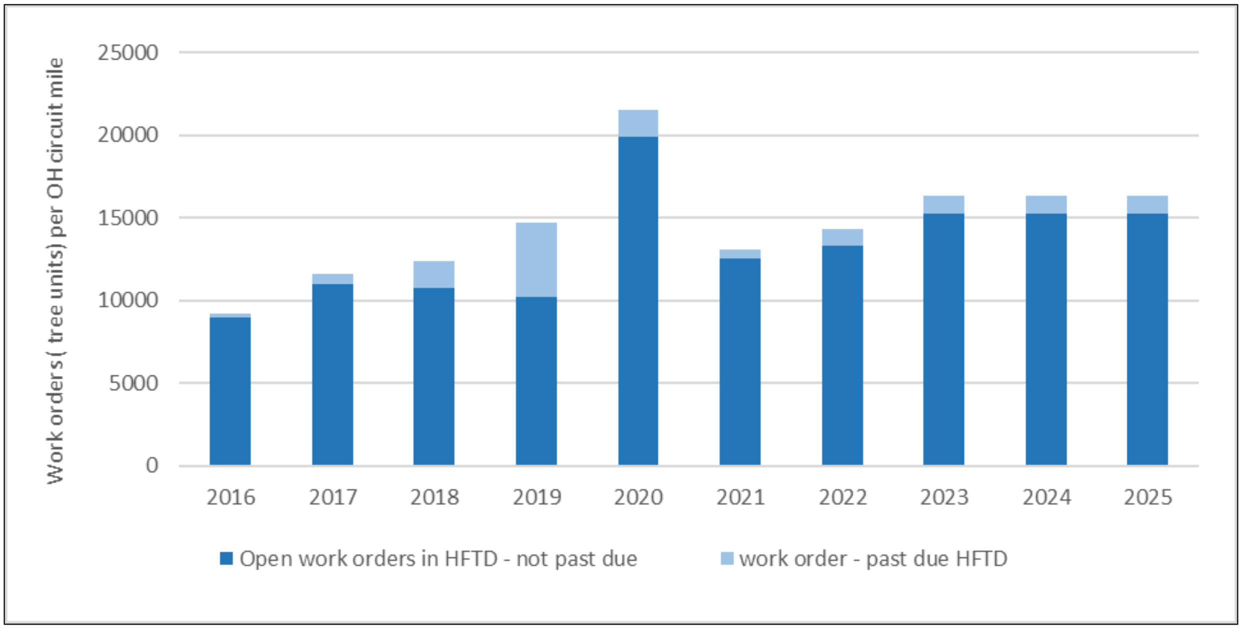
PowerWorkz allows tracking and reporting of the status for all open, pending, and completed SWO, DWO, and memo work orders. Additionally, it can track and report the condition code activity status at the asset level for all tree and pole brush records. SDG&E is also in the process of creating dashboards that can report work order status and backlog.

8.2.6.4 Work Order Trends

Vegetation Management tracks work orders as a function of activity completion and schedule. Some types of work orders such as SWOs must be completed in the work management system before the contractor can perform invoicing for that VMA activity. Contractors monitor and complete DWOs and SWOs as a weekly and monthly administrative function. As an ad-hoc creation, memo work orders do not have the system requirement to complete before the contractor can invoice. However, the contractors must code an individual asset record complete before the work can be invoiced.

Figure 8-34 shows the average open work orders (pending tree trim or tree removal) per OH circuit mile in the HFTD. Approximately 6 percent of HFTD trees remain as open work orders at year-end each year. This is driven by the timing of the work with the inspections taking place towards the end of the year and the associated trimming to be completed within the first quarter of the following year. SDG&E has also remained up-to-date with its vegetation work, averaging approximately 0.54 trees per overhead circuit mile (0.4 percent of HFTD trees) with past due orders pending at the end of the calendar year. SDG&E’s forecasts for future open work orders are expected to remain aligned with the most recent 5-year average.

Figure 8-34: Open Work Orders in the HFTD



OEIS Table 8-19 shows the total number of tree units within the HFTD that were past due at the end of 2022. Work order scheduling is dependent on the condition code of the tree. Routine work is generally scheduled to be completed within 120 days of inspection, whereas priority work is generally scheduled to be completed within 30 days of inspection.

OEIS Table 8-19: Number of Past Due Vegetation Management Work Orders (Tree Units) Categorized by Age

HFTD Area	0-30 days	31-90 days	91-180 days	181+ days
HFTD Tier 2	79	533	4	2
HFTD Tier 3	357	20	5	1

8.2.7 Workforce Planning (WMP.506)

Much of the Vegetation Management workforce is comprised of contractor personnel and includes over 300 individuals combined for pre-inspection, tree trimming, pole brushing, and audit activities. The internal Vegetation Management workforce includes approximately 20 personnel including Managers, Area Foresters, Contract Administrators, Patrollers, Business Advisor, Data Specialist, and Administrative.

Contractors are responsible for recruiting and training their employees including utility regulations, fire awareness, electrical safety, hardware identification, and activity-specific work processes and procedures. SDG&E provides contractor training for its work management system including hardware and software applications. Contractors are additionally required to perform in-house annual refresher training that includes the following modules: fire preparedness, environmental protection, hazard tree assessment, and customer service.

Vegetation Management provides initial training for all its internal personnel including the subjects referenced above as well as annual refresher training for environmental, safety, compliance, fire preparedness, and vehicle driver safety. Additionally, SDG&E employees receive online refresher training annually on Affiliate Compliance Rules, Business Conduct and Ethics, North American Electric Reliability Corporation (NERC) Compliance, Customer Information, and Diversity & Inclusion.

SDG&E sponsors and participates in Utility Line Clearance Arborist training sessions in collaboration with the San Diego Community College District, Utility Arborist Association, California Conservation Corps (CCC), and the Urban Corps of San Diego County. The purpose of these training sessions is to train participants to become professional, qualified line-clearance arborists. For more information see response to Areas for Continued Improvement SDGE 22-03 in Appendix D.

SDG&E received the Tree Line USA® recognition for the twentieth consecutive year in 2022. Tree Line USA is awarded by the National Arbor Day Foundation to utilities that demonstrate best practices in utility arboriculture, and how trees and utilities can effectively co-exist for the benefit of communities. The five core standards utilities must meet to be recognized include annual worker training, quality tree care, tree planting and public education, tree-based energy conservation program, and annual Arbor Day events in collaboration with community groups.

OEIS Table 8-20: Vegetation Management Qualifications and Training

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Vegetation Management Compliance Manager	Bachelor's Degree in Forestry, Biology, or Horticulture and/or equivalent training/experience 7 years' experience in Utility Vegetation Management, including 3 years in contractor management	International Society of Arboriculture (ISA) Certified Arborist ISA Utility Specialist	5%	5%	n/a	n/a	International Society of Arboriculture Certified Arborist Program
Vegetation Management WMP Manager	Bachelor's Degree in Forestry, Biology, or Horticulture and/or equivalent training/experience 7 years' experience in Utility Vegetation Management, including 3 years in contractor management	International Society of Arboriculture (ISA) Certified Arborist ISA Utility Specialist	5%	5%	n/a	n/a	International Society of Arboriculture Certified Arborist Program
Vegetation Management Operational Manager	Bachelor's Degree in Forestry, Biology, or Horticulture and/or equivalent training/experience 7 years' experience in Utility Vegetation Management, including 3 years in contractor management	International Society of Arboriculture (ISA) Certified Arborist ISA Utility Specialist	5%	5%	n/a	n/a	International Society of Arboriculture Certified Arborist Program
Vegetation Management Business Advisor	Bachelor's degree in Finance, Accounting, Data Analytics, Business Administration, or related	No special certification required	5%	n/a	n/a	n/a	n/a
Vegetation Management Senior Data Analyst	Bachelor's degree in Engineering, Economics, Finance, Data Analytic, or related	No special certification required	5%	n/a	n/a	n/a	n/a
Area Forester/ Contract Administrator	3 years' Utility Vegetation Management experience Bachelor's degree in Forestry, Biology, Horticulture, or related field (preferred)	International Society of Arboriculture (ISA) Certified Arborist	30%	30%	n/a	n/a	International Society of Arboriculture Certified Arborist Program

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
Vegetation Management Lead Forester	Bachelor's degree in Forestry, Biology, Horticulture, or related field (preferred) 3-5 years' experience administering vegetation management programs Supervisory experience working with external contractors	International Society of Arboriculture (ISA) Certified Arborist	10%	10%	n/a	n/a	International Society of Arboriculture Certified Arborist Program
Forester Patrol Person	3 years' utility vegetation management experience Bachelor's degree in Forestry, Biology, Environmental Science, Horticulture, or related field (preferred)	International Society of Arboriculture (ISA) Certified Arborist	20%	20%	n/a	n/a	International Society of Arboriculture Certified Arborist Program
Resource Coordinator (Customer Help Desk)	High school diploma; college courses (preferred) 3 years' customer service experience Microsoft Office proficiency; Strong technical writing skills (preferred) Working knowledge of Mainframe, GIS, SAP and Distribution Planning Scheduling applications (preferred)	No special certification required	15%	n/a	n/a	n/a	n/a
Auditor	Bachelor's degree in Forestry, Biology, Environmental Science, Horticulture, or related field (preferred) Current Class C Driver's License with clean driver safety record	International Society of Arboriculture (ISA) Certified Arborist	n/a	n/a	4%	54%	International Society of Arboriculture Certified Arborist Program
Pre-Inspector	Bachelor's degree in Forestry, Biology, Environmental Science, Horticulture, or related field (preferred)	International Society of Arboriculture (ISA) Certified Arborist	n/a	n/a	19%	80%	International Society of Arboriculture Certified Arborist Program

Worker title	Minimum Qualifications for Target Role	Special Certification Requirements	Electrical Corporation % FTE Min Quals	Electrical Corporation % Special Certifications	Contractor % FTE Min Quals	Contractor % Special Certifications	Reference to Electrical Corporation Training/ Qualification Programs
	Current Class C Driver's License with clean driver safety record						
Tree Trim General Foreperson/ Supervisor	5 years' line clearance tree pruning experience as a Foreman Current California Driver License Class B endorsement General computer knowledge Strong leadership qualities	International Society of Arboriculture (ISA) Certified Arborist	n/a	n/a	5%	62%	International Society of Arboriculture Certified Arborist Program
Tree Trimmer	Current California Driver License (Class B endorsement) General computer skills Strong work ethic	Line-clearance qualified arborist certification (or trainee)	n/a	n/a	63%	87%	United States Department of Labor Standard OSHA 1910.269; ANSI Z133 Safety Standards
Pole Brush General Foreman / Supervisor	5 years' line clearance tree pruning experience as a Foreman Current California Driver License Class B endorsement General computer knowledge Strong leadership qualities	Qualified Applicator Certification	n/a	n/a	1%	40%	California Department of Pesticide Regulation Licensing Program
Pole Brusher	Current California Driver License (Class B endorsement) General computer skills Strong work ethic	No special certification required	n/a	n/a	8%	n/a	n/a
Total			**100%**		**100%**		

ATTACHMENT F.2

OFFICE OF ENERGY INFRASTRUCTURE SAFETY DECISION FOR SAN DIEGO GAS & ELECTRIC COMPANY’S 2025 PETITION TO AMMEND TO ITS 2023-2025 BASE WILDFIRE MITIGATION PLAN

JULY 11, 2025

State of California – A Natural Resources Agency
Gavin Newsom, Governor

OFFICE OF ENERGY INFRASTRUCTURE SAFETY
715 P Street, 15th Floor | Sacramento, CA 95814
916.902.6000 | *www.energysafety.ca.gov*
Caroline Thomas Jacobs, Director

July 11, 2025

Brian D'Agostino
Vice President – Wildfire & Climate Science
San Diego Gas & Electric Company
BDAgostino@sdge.com

Subject: **Office of Energy Infrastructure Safety Decision for San Diego Gas & Electric Company's 2025 Petition to Amend to its 2023-2025 Base Wildfire Mitigation Plan**

Mr. D'Agostino:

The Office of Energy Infrastructure Safety (Energy Safety) has evaluated San Diego Gas & Electric Company's (SDG&E's) Petition to Amend, submitted on April 10, 2025, pursuant to Chapter IV of the Wildfire Mitigation Plan Guidelines (WMP Guidelines).[1] The petition seeks to amend SDG&E's 2023-2025 Base Wildfire Mitigation Plan (2023-2025 Base WMP).

Energy Safety hereby approves six amendments requested by SDG&E and denies 11 amendments.[2]

On May 16, 2022, SDG&E submitted its General Rate Case (GRC) application for 2024 Test Year with the California Public Utilities Commission (CPUC).[3] On December 23, 2024, the CPUC issued its decision addressing Track 1 of SDG&E 2024 Test Year.[4] In its decision, CPUC

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[1] Office of Energy Infrastructure Safety, Wildfire Mitigation Plan Guidelines, Published February 24, 2025, pages 172-174, URL:(https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58026&shareable=true).

[2] Where an electrical corporation deviates from its approved WMP, it may explain or justify such deviations during the compliance process.

[3] San Diego Gas & Electric Company, Test year 2024 general rate case application of San Diego Gas & Electric company (U 902 M), Published May 17, 2022, URL: (https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M476/K452/476452353.PDF).

[4] California Public Utility Commission, Decision addressing the 2024 test year general rate cases of Southern California Gas Company and San Diego Gas & Electric Company, D. 24-12-074, Published December 23, 2024, URL: (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf).

authorized funding to underground electrical lines, but not to the amount requested by SDG&E.[5]

SDG&E subsequently submitted a Petition to Amend to Energy Safety requesting amendments to five 2024 and twelve 2025 initiatives and targets in its 2023-2025 Base WMP.[6] SDG&E identified that its GRC application forecasts formed the basis for the development of its 2024 and 2025 WMP targets.[7] SDG&E argued that it must reduce SDG&E's wildfire mitigation spending for 2025, 2026, and 2027 to ensure that its WMP spending stays within its authorized revenue requirement for the 2024-2027 GRC Cycle.[8] SDG&E provided projected expenditure adjustments in a table in the petition's Attachment A and redlined amendments to its 2023-2025 Base WMP in Attachment B.

Below, Energy Safety provides a summary of its determination for each of the 17 requested amendments.

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[5] California Public Utility Commission, Decision addressing the 2024 test year general rate cases of Southern California Gas Company and San Diego Gas & Electric Company, D. 24-12-074, pages 466 & 495, Published December 23, 2024, URL: (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf)..

[6] San Diego Gas & Electric Company, San Diego Gas & Electric 2025 Petition to Amend, Published April 10, 2025, URL: (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58234&shareable=true).

[7] San Diego Gas & Electric Company, San Diego Gas & Electric 2025 Petition to Amend, page 3, Published April 10, 2025, URL: (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58234&shareable=true).

[8] San Diego Gas & Electric Company, San Diego Gas & Electric 2025 Petition to Amend, page 5, Published April 10, 2025, URL: (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58234&shareable=true).

Table 1. Determinations for SDG&E-Requested Amendments

Tracking ID and Title	Amendment Requested	Determination	Rationale
WMP.549 Distribution Communication Reliability Improvement (2024)	SDG&E proposes completing 5 base stations in 2024, versus the approved 60 base stations, for cost efficiency and affordability.	Denied	SDG&E did not show good cause for the amendments requested in the petition. The performance period had elapsed.
WMP.468 Standby Power Program (2024)	SDG&E proposes providing 58 generators in 2024, versus the approved 300 generators, for cost efficiency and affordability.	Denied	SDG&E did not show good cause for the amendments requested in the petition. The performance period had elapsed.
WMP.552 Drone Assessments (2024)	SDG&E proposes conducting 6,500 inspections in 2024, versus the approved 13,500 inspections, for cost efficiency and affordability.	Denied	SDG&E did not show good cause for the amendments requested in the petition. The performance period had elapsed.
WMP.481 Distribution Infrared Inspections (2024)	SDG&E proposes conducting 300 inspections in 2024, versus the approved 9,532 inspections, for cost efficiency and affordability, and due to a 0.2 percent find rate.	Denied	SDG&E did not show good cause for the amendments requested in the petition. The performance period had elapsed.

Tracking ID and Title	Amendment Requested	Determination	Rationale
WMP.497 Fuel Management (2024)	SDG&E proposes reducing this program to 150 poles in 2024, versus the approved 500 poles, for cost efficiency and affordability.	Denied	SDG&E did not show good cause for the amendments requested in the petition. The performance period had elapsed.
WMP.473 Strategic Undergrounding (2025)	SDG&E proposes to install 28 miles of undergrounding, versus the approved 125 miles, consistent with the GRC decision.	Approved	The request meets all required criteria of Chapter IV of the WMP Guidelines.
WMP.455 Covered Conductor (2025)	SDG&E proposes to install 50 miles of covered conductor, versus the approved 40 miles, consistent with the GRC decision.	Approved	The request meets all required criteria of Chapter IV of the WMP Guidelines.
WMP.1189 Strategic Pole Replacement Program (2025)	SDG&E proposes to replace 200 poles, versus the approved 291 poles, to further align WMP programs with the GRC decision.	Approved	The request meets all required criteria of Chapter IV of the WMP Guidelines. While this target change will result in less risk reduced, SDG&E's distribution poles have low failure and ignition rates. Additionally, the proposed target is consistent with Energy Safety's approval of a 200-pole target in SDG&E's 2023-2025 Base WMP prior to SDG&E

Tracking ID and Title	Amendment Requested	Determination	Rationale
			raising the target to 291 poles in its 2025 WMP Update.[9]
WMP.543 Transmission OH Hardening (2025)	SDG&E proposes to harden 2 miles, versus the approved 4.64 miles, due to a dependency on distribution underbuild that was previously scoped for strategic undergrounding but will no longer be performed in 2025 due to the undergrounding program reductions.	Approved	The request meets all required criteria of Chapter IV of the WMP Guidelines.
WMP.550 Lightning Arrester Removal/ Replacement (2025)	SDG&E proposes to install or replace 90 lighting arrestors, versus the approved 1,848, to deploy them with the deployment of covered conductor and continue to replace them as needed, rather than proactive deployment.	Approved	The request meets all required criteria of Chapter IV of the WMP Guidelines. While this target change will result in less risk reduced, SDG&E's lightning arrestors demonstrated low failure and ignition rates from 2022 to 2024.

[9] San Diego Gas & Electric Company, 2025 Wildfire Mitigation Plan Update, page 32, Published April 2, 2024, URL: (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=56449&shareable=true).

Tracking ID and Title	Amendment Requested	Determination	Rationale
WMP.464 Connectors, including hotline clamps; WMP.972 Avian Protection; WMP.459 Expulsion Fuse Replacement (2025)	SDG&E proposes the following target reductions: • WMP.464: 950 → 100 hotline clamps • WMP.972: 200 → 95 poles • WMP.459: 700 → 80 fuses SDG&E identifies that it intends to deploy these mitigations with the deployment of covered conductor and continue to replace them as needed, rather than proactive deployment.	Denied	This request does not meet the requirements set forth in Chapter IV of the WMP Guidelines. This request does not align with the GRC decision. The GRC decision authorized SDG&E’s full request for this activity.[10] Furthermore, SDG&E did not show good cause for the amendments requested in the petition. SDG&E has identified distribution connectors as having high failure and ignition rates. SDG&E has reported 11 ignitions in the HFTD from animal contact from 2022 through 2024, with 5 occurring in 2024. SDG&E has identified that distribution fuses and cutouts as having high ignition rates. With 97 less miles scoped for undergrounding and only ten additional miles scoped for covered conductor, it is not clear that SDG&E’s approach will sufficiently reduce risk.
WMP.549 Distribution Communication Reliability	SDG&E proposes to install 5 base stations, versus the approved 42 base stations, to further align WMP programs with the GRC.	Approved	The request meets all required criteria of Chapter IV of the WMP Guidelines.

[10] California Public Utility Commission, Decision addressing the 2024 test year general rate cases of Southern California Gas Company and San Diego Gas & Electric Company, D. 24-12-074, page 485, Published December 23, 2024, URL: (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf).

Tracking ID and Title	Amendment Requested	Determination	Rationale
Improvement (2025)			
WMP.552 Drone Assessments (2025)	SDG&E proposes conducting 6,500 inspections, versus the approved 13,500 inspections, for cost efficiency and affordability. SDG&E also identified that the re-evaluated number was aimed to balance expected risk reduction with expected repair and replacement costs and timelines.[11]	Denied	This request does not meet the requirements set forth in Chapter IV of the WMP Guidelines. This request does not align with the GRC decision. The GRC decision authorized SDG&E's full request for this activity.[12] Furthermore, SDG&E did not show good cause for the amendment requested in the petition. SDG&E's find rate for drone inspections is considerably greater than its find rate for detailed inspections. This proposal would likely result in a significant amount of risk left unidentified.
WMP.494 Detailed Vegetation Inspections (2025)	SDG&E proposes conducting 255,000 inspections, versus the approved 485,400 inspections, to reflect only inspections conducted in HFTD, consistent with the GRC decision.	Denied	This request does not meet the requirements set forth in Chapter IV of the WMP Guidelines. The request does not align with the GRC decision. The GRC authorized less funding than SDG&E's GRC request based on a lower forecast cost, not a

[11] San Diego Gas & Electric Company, SDG&E Response OEIS-P-WMP_2025-SDGE-04, Question 9, Published May 22, 2025, URL: (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58533&shareable=true).

[12] California Public Utility Commission, Decision addressing the 2024 test year general rate cases of Southern California Gas Company and San Diego Gas & Electric Company, D. 24-12-074, pages 486 & 493, Published December 23, 2024, URL: (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf).

Tracking ID and Title	Amendment Requested	Determination	Rationale
			reduced scope of work.[13] SDG&E identified that this work is eligible to be booked in its Vegetation Management Memorandum Account (VMMA).[14] SDG&E may have an opportunity to recover costs through the VMMA above those authorized in the GRC if SDG&E is able to demonstrate that its assumptions on unit cost were justified. The GRC Decision did not direct SDG&E to only include inspections conducted in HFTD in its WMPs; rather, the GRC decision included both HFTD and non-HFTD vegetation inspections in its Wildfire Mitigation and Vegetation Management authorizations.[15]
WMP.512 Pole Clearing (2025)	SDG&E proposes clearing 22,000 poles, versus the approved 33,100 poles, as it intends in 2025 to begin	Denied	This request does not meet the requirements set forth in Chapter IV of the WMP Guidelines. This request does not align with the GRC decision. The

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[13] California Public Utility Commission, Decision addressing the 2024 test year general rate cases of Southern California Gas Company and San Diego Gas & Electric Company, D. 24-12-074, pages 491-493, Published December 23, 2024, URL: (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf).

[14] San Diego Gas & Electric Company, SDGE Response OEIS-P-WMP_2025-SDGE-04, Question 11, Published May 22, 2025, URL: (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58533&shareable=true).

[15] California Public Utility Commission, Decision addressing the 2024 test year general rate cases of Southern California Gas Company and San Diego Gas & Electric Company, D. 24-12-074, pages 491-494, Published December 23, 2024, URL: (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf).

Tracking ID and Title	Amendment Requested	Determination	Rationale
	including only poles that are not exempt from Public Resources Code § 4292 requirements.		GRC authorized a lower request due based on a lower forecast cost for the work, not a reduction in its scope.[16] SDG&E identified that this work is eligible to be booked in its Vegetation Management Memorandum Account (VMMA).[17] SDG&E may have an opportunity to recover costs through the VMMA above those authorized in the GRC if SDG&E is able to demonstrate that its assumptions on unit cost were justified.

[16] California Public Utility Commission, Decision addressing the 2024 test year general rate cases of Southern California Gas Company and San Diego Gas & Electric Company, D. 24-12-074, pages 489-490, Published December 23, 2024, URL: (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M550/K485/550485071.pdf).

[17] San Diego Gas & Electric Company, SDGE Response OEIS-P-WMP_2025-SDGE-04, Question 11, Published May 22, 2025, URL: (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58533&shareable=true).

Summary

Energy Safety denies the five SDG&E amendment requests affecting targets for the following 2024 initiatives:

- WMP.549: Distribution Communication Reliability Improvement
- WMP.468: Standby Power Program
- WMP.552: Drone Assessments
- WMP.481: Distribution Infrared Inspections
- WMP.497: Fuel Management

Energy Safety approves six of SDG&E's 17 amendment requests, affecting targets for the following 2025 initiatives:

- WMP.473: Strategic Underground
- WMP.455: Covered Conductor
- WMP.1189: Strategic Pole Replacement Program
- WMP.543: Transmission OH Hardening
- WMP.550: Lightning Arrester Removal/ Replacement
- WMP.549: Distribution Communication Reliability Improvement

Energy Safety denies six of SDG&E's 17 amendment requests, affecting the following 2025 initiatives:

- WMP.464: Connectors, including hotline clamps
- WMP.972: Avian Protection
- WMP.459: Expulsion Fuse Replacement
- WMP.552: Drone Assessments
- WMP.494: Detailed Vegetation Inspections
- WMP.512: Pole Clearing

Energy Safety finds SDG&E did not associate any amendments with WMP.462 Microgrids.

Next Steps

In accordance with the WMP Guidelines, SDG&E must include only the amendments to the approved targets and the projected or planned expenditure changes associated with the approved targets in future submissions to Energy Safety. SDG&E must revise its data reporting to reflect approved changes to WMP activity and financial targets according to Data Guidelines v4.01.[18]

SDG&E must revise its last approved Base WMP to reflect only the approved target amendments for 2025, as noted above. SDG&E must revise Table 4-1: Summary of WMP Expenditures and Figure 4-1: Summary of WMP Expenditures to only reflect changes to planned expenditures that are associated with the approved target amendments, as identified in Attachment A of its Petition to Amend. SDG&E must submit the revised 2023-2025 Base WMP to the 2023-2025 Wildfire Mitigation Plan docket (#2023-2025-Base-WMPs)[19] no later than July 25, 2025.

Sincerely,

Nicole Dunlap

Program Manager | Electrical Safety Policy Division

Office of Energy Infrastructure Safety

[18] Office of Energy Infrastructure Safety, [Energy Safety Data Guidelines v4.01](https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58132&shareable=true), Published March 21, 2025, URL: (https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58132&shareable=true).

[19] Office of Energy Infrastructure Safety, 2023 - 2025 Electrical Corporation Wildfire Mitigation Plans docket, Accessed April 10, 2025, URL: (https://efiling.energysafety.ca.gov/EFiling/DocketInformation.aspx?docketnumber=2023-2025-WMPs).

ATTACHMENT G

MICHAEL W. FOSTER DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	A.22-05-015 (Filed May 16, 2022)
And Related Matter.	A.22-05-016 (Filed May 16, 2022)

DECLARATION OF MICHAEL W. FOSTER ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.24-12-074

I, Michael W. Foster, declare that:

1. I am currently employed by Southern California Gas Company ("SoCalGas") as the Rate Design and Demand Forecasting Manager within the Gas Regulatory Affairs Department. My current responsibilities include overseeing load forecasting, rate design, and rate implementation for SoCalGas and San Diego Gas & Electric Company's ("SDG&E") natural gas service. I sponsored testimony on behalf of SoCalGas and SDG&E in Track 1 of the above-captioned Test Year ("TY") 2024 General Rate Case ("GRC") proceeding, supporting gas affordability metrics.[1]

2. The purpose of my declaration is to provide factual support for SoCalGas's Petition for Modification ("Petition" or "PFM") of Decision ("D.") 24-12-074, issued on December 23, 2024 (hereinafter referred to as the "2024 GRC Decision").

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[1] Exhibits ("Ex.") SCG-43-S, SDG&E-51-S, SCG-243/SDG&E-250.

Post Test-Year Rate Changes and Implementation

3. The declaration of Khai Nguyen describes the revenue requirement requested in this Petition and the increase above the 2024 GRC Decision's authorized revenue requirements.

4. If the Petition is granted, SoCalGas proposed to implement any rate changes associated with any remaining full post-test year(s) on January 1 of that year through the currently adopted process.

5. If the Petition is granted, SoCalGas proposes to record the difference between the Petition's final decision and D.24-12-074 in the GRC memorandum account ("GRCMA") until implemented. SoCalGas proposes to amortize amounts recorded in the GRCMA in rates over a minimum 12-month period, commencing on August 1, 2026, if possible, but will coordinate with existing rate change schedules to mitigate potential rate volatility. Any partial year rate change may be implemented at the next scheduled rate change or as approved by Energy Division.

6. The change in gas revenue presented in Mr. Nguyen's declaration would result in residential and core commercial/industrial customers' bundled revenues to increase by 1.5% and 1.1%, respectively for 2025, 3.5% and 2.7%, respectively for 2026, and by 5.4% and 4.1%, respectively for 2027.[2]

Estimated Bill Impacts

7. Table 1 below provides the estimated bill impacts for gas customers. Table 1 shows the average monthly bill for a gas non-CARE residential customer would increase by $1.09 per month, or 1.5% in 2025, increase by $2.65 per month, or 3.6% in 2026, and increase

[2] Bundled revenues includes transportation, public purpose programs surcharges, and gas commodity. Gas commodity revenues are estimated by multiplying the gas procurement charge by the ratemaking throughput for each of the residential and core commercial/industrial classes.

by $4.03 per month, or 5.4% in 2027. The average monthly bill for a gas CARE residential customer would increase by $0.61 per month, or 1.5% in 2025, increase by $1.49 per month, or 3.6% in 2026 and increase by $2.26 per month, or 5.4% in 2027.[3]

Table 1. SoCalGas Illustrative Gas Bill Impact[4,5]

Monthly Bill Impact		Current (10/1/25)	2025 Increase	2026 Increase	2027 Increase
Change ($)	Non-CARE	$74.47	$1.09	$2.65	$4.03
	CARE	$41.65	$0.61	$1.49	$2.26
Change (%)	Non-CARE		1.5%	3.6%	5.4%
	CARE		1.5%	3.6%	5.4%

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 17th day of December 2025, at Los Angeles, California.

/s/ Michael William Foster
Michael William Foster

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[3] The bill impacts are based on current effective rates and models as of October 1, 2025 and reflect as if the requested relief in the Petition were implemented timely at the beginning of each year. The actual bill impacts will differ based upon the models in effect upon implementation and the amortization period to account for the delay in the cost recovery.
[4] The bill impacts are based on current effective rates and models as of October 1, 2025 and reflect as if the requested relief in the Petition were implemented timely at the beginning of each year. The actual bill impacts will differ based upon the models in effect upon implementation and the amortization period to account for the delay in the cost recovery.
[5] Annual average bill impact for a typical residential customer using 36 therms per month.

ATTACHMENT H

RACHELLE R. BAEZ AND MICHAEL W. FOSTER DECLARATION

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2024.	A.22-05-015 (Filed May 16, 2022)
And Related Matter.	A.22-05-016 (Filed May 16, 2022)

DECLARATION OF RACHELLE R. BAEZ AND MICHAEL W. FOSTER ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF THE JOINT PETITION FOR MODIFICATION OF D.24-12-074

We, Rachelle R. Baez and Michael W. Foster, declare that:

1. I, Rachelle R. Baez, am currently employed by San Diego Gas & Electric Company ("SDG&E") as the Electric Rates Implementation Manager. My current responsibilities include overseeing the implementation of SDG&E's electric rates and ensuring compliance with state and federal regulatory and legislative requirements. I sponsored testimony on behalf of SDG&E in Track 1 of the above-captioned Test Year ("TY") 2024 General Rate Case ("GRC") proceeding, supporting electric affordability metrics.[1]

2. I, Michael W. Foster, am currently employed by Southern California Gas Company ("SoCalGas") as the Rate Design and Demand Forecasting Manager within the Gas Regulatory Affairs Department. My current responsibilities include overseeing load forecasting, rate design, and rate implementation for SoCalGas and SDG&E's natural gas service. I sponsored testimony on behalf of SoCalGas and SDG&E in Track 1 of the above-captioned TY 2024 GRC proceeding, supporting gas affordability metrics.[2]

[1] Exhibits ("Ex.") SDG&E-50-S, SDG&E-250.
[2] Ex. SCG-43-S, SDG&E-51-S, SCG-243/SDG&E-250.

3. The purpose of our declaration is to provide factual support for the Petition for Modification ("Petition" or "PFM") of Decision ("D.") 24-12-074, issued on December 23, 2024 (hereinafter referred to as the "2024 GRC Decision").

Post Test-Year Rate Changes and Implementation

4. The declaration of Melanie E. Hancock describes the revenue requirement requested in this Petition and the increase above the 2024 GRC Decision's authorized revenue requirements.

5. If the Petition is granted, SDG&E proposes to implement any rate changes associated with any remaining full post-test year(s) on January 1 of that year through the currently adopted process.

6. If the Petition is granted, SDG&E proposes to record the difference between the Petition's final decision and D.24-12-074 in the GRC memorandum account ("GRCMA") until implemented. SDG&E proposes to amortize amounts recorded in the GRCMA in rates over a minimum 12-month period, commencing on August 1, 2026, if possible, but will coordinate with existing rate change schedules to mitigate potential rate volatility. Any partial year rate change may be implemented at the next scheduled rate change or as approved by Energy Division.

7. The change in electric revenue presented in Ms. Hancock's declaration would result in a system average rate impact of 0.2 cents/kWh, or 0.6%, in 2025; 0.6 cents/kWh, or 1.6%, in 2026; and 0.9 cents/kWh, or 2.6%, in 2027.[3]

8. The change in gas revenue presented in Ms. Hancock's declaration would result in residential and core commercial/industrial customers' bundled revenues to increase by 0.8% and

[3] The rate impacts are based on current effective rates and models as of October 1, 2025 and reflect as if the requested relief in the PFM were implemented timely at the beginning of each year. The actual rate impacts will differ based upon the models in effect upon implementation and the amortization period to account for the delay in the cost recovery.

0.4%, respectively for 2025, 1.3% and 0.6%, respectively for 2026, and by 1.3% and 0.6%, respectively for 2027.[4]

Estimated Bill Impacts

9. Tables 1 and 2 below provide the estimated bill impacts for electric and gas customers.

10. Table 1 shows that a typical non-California Alternate Rates for Energy ("CARE") electric residential customer would see an increase of approximately $1.37 per month, or 0.8% in 2025; $3.23 per month, or 1.8%, in 2026; and $5.11 per month, or 2.8%, in 2027. A typical CARE electric residential customer would see an increase of approximately $0.90 per month, or 0.9%, in 2025; $2.12 per month, or 2.0%, in 2026; and $3.33 per month, or 3.1%, in 2027.

Table 1. SDG&E Illustrative Residential Electric Bill Impacts[5,6]

Monthly Bill Impact[7]		Current (10/1/25)	2025 Increase	2026 Increase	2027 Increase
Change ($)	Non-CARE	$176.33	$1.37	$3.23	$5.11
	CARE	$102.87	$0.90	$2.12	$3.33
Change (%)	Non-CARE		0.8%	1.8%	2.8%
	CARE		0.9%	2.0%	3.1%

11. As shown in Table 2, the average monthly bill for a gas non-CARE residential customer would increase by $0.54 per month, or 0.8% in 2025, increase by $0.86 per month, or 1.3% in 2026 and increase by $0.87 per month, or 1.3% in 2027. The average monthly bill for a

[4] Bundled revenues includes transportation, public purpose programs surcharges, and gas commodity. Gas commodity revenues are estimated by multiplying the gas procurement charge by the ratemaking throughput for each of the residential and core commercial/industrial classes.
[5] The bill impacts are based on current effective rates and models as of October 1, 2025 and reflect as if the requested relief in the PFM were implemented timely at the beginning of each year. The actual bill impacts will differ based upon the models in effect upon implementation and the amortization period to account for the delay in the cost recovery.
[6] Annual average bill impact for a typical bundled residential customer using 400kwh per month on Schedule TOU-DR1.
[7] "Monthly Bill Impact" refers to the average monthly bill impact for bills over a full calendar year.

gas CARE residential customer would increase by \$0.36 per month, or 0.8% in 2025, increase by \$0.58 per month, or 1.3% in 2026 and increase by \$0.58 per month, or 1.3% in 2027.[8]

Table 2. SDG&E Illustrative Gas Bill Impact[9,10]

Monthly Bill Impact		Current (10/1/25)	2025 Increase	2026 Increase	2027 Increase
Change (\$)	Non-CARE	\$65.32	\$0.54	\$0.86	\$0.87
	CARE	\$43.44	\$0.36	\$0.58	\$0.58
Change (%)	Non-CARE		0.8%	1.3%	1.3%
	CARE		0.8%	1.3%	1.3%

We declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, except as to those matters stated to be on information and belief, and as to those matters, I believe them to be true and correct.

Executed this 17th day of December 2025, at San Diego, California.

/s/ Rachelle R. Baez
Rachelle R. Baez

/s/ Michael W. Foster
Michael W. Foster

[8] The bill impacts are based on current effective rates and models as of October 1, 2025 and reflect as if the requested relief in the Petition were implemented timely at the beginning of each year. The actual bill impacts will differ based upon the models in effect upon implementation and the amortization period to account for the delay in the cost recovery.
[9] The bill impacts are based on current effective rates and models as of October 1, 2025 and reflect as if the requested relief in the Petition were implemented timely at the beginning of each year. The actual bill impacts will differ based upon the models in effect upon implementation and the amortization period to account for the delay in the cost recovery.
[10] Annual average bill impact for a typical residential customer using 24 therms per month.

ATTACHMENT I

Post Test Year Ratemaking: Timing, Attrition, and the Balancing of Interests

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1. Introduction

The regulation of public utilities has, from its inception, struggled with designing a non-market process that harnesses competitive forces while balancing the, often contradictory, interests of stakeholders. What makes this task difficult is the long-term relationship specific investments utilities must undertake to deliver necessary services over time. Setting rates prospectively, while at the same time leaving rates unchanged until reset by the regulator, inherently leaves utility earnings subject to the whims of changes in the operating environment. Under favorable economic conditions, the process may work well enough to provide the necessary inducement for on-going investment in the system. Under less favorable conditions, the process must adjust to maintain the balance between those investing in providing services and those consuming those services.

This paper reviews the discovery process that is the US regulatory structure and finds that the balancing of interests requires the regulator to find the level of prudent cost, including the cost of capital, such that customers are assured of receiving an adequate level of service over time. This balancing is necessary due to the regulatory compact whereby owners of private property willingly submit to regulation in return for an opportunity to recover prudently incurred costs. Regulators consider the interests of consumers in this bargain by limiting rates to only the prudent level of costs as estimated in a one-year test period (i.e., the test year). Under this bargain, the regulatory process creates a breakeven constraint which provides the utility an opportunity to recover expenses while keeping economic profit at the competitive level (i.e., zero).

Changing economic conditions can fundamentally impinge the ability of the regulator to fairly implement the regulatory contract. Less stable prices due to unexpected inflation, reductions in sales growth due to a maturing industry and policies supportive of sales reductions, and reductions in overall industry productivity as capital requirements increase at the same time sales stagnate or fall, create difficulties in providing a fair opportunity to recover reasonable costs. These factors have, in many cases, led to declining earnings between rate-setting proceedings, a process referred to as attrition.

The paper then reviews the changes to the regulatory process in response to the changing economic environment to address attrition. We find that regulators have made several pragmatic adjustments over the past century to maintain the balance of the regulatory contract. Early modifications to the regulatory process included basic adjustment clauses that provide more frequent non-test year adjustments to rates to address volatile fuel and gas costs. As broader economic conditions changed, namely unexpected inflation, future or projected test years were adopted to avoid creating rates based on stale data which held out the possibility of limiting attrition. Other factors, such as sales growth declines, led regulators toward attrition adjustments outside the test year based on proxies for changes in costs, such as the number of customers, while leaving the profit level unchanged until the next full review of costs. This decoupling of sales and profit levels helped match public policy toward energy efficiency with utility profit incentives while limiting attrition of earnings between rate setting proceedings.

More recently, regulators have moved toward multiple year rate cases with specific attrition factors for expenses and capital. These multi-year plans better address the specific attrition factors, namely the growth in capital expense as utilities replace worn out plant and equipment while investing in new technology to capture efficiencies. Multi-year rate plans, as a process, seem to address the balance between investment needs and consumer protection, though regulators need to carefully implement attrition factors in these plans to recognize the difference between capital costs over time and operation and maintenance expenses. Most multi-year rate plans use a separate attrition factor for capital to maintain the balance over the plan by matching attrition factors in a manner that better proxies how the costs change over time which lessens the attrition in earnings.

Regulation would not have been implemented in these industries, and it would not have lasted, if the utility industry did not exhibit characteristics of monopoly and the services provided by utilities were not deemed necessary for modern life. Utilities provide a public service, yet they are not public companies. The intent of the regulatory compact was to induce private investors to provide capital such that necessary services are provided to the public. Ultimately, the goal of limiting attrition in earnings is to allow the utility to uphold its part of the regulatory contract by attracting capital to the utility sector. Addressing attrition through the regulatory process is one method to help keep the balance in the bargain to the benefit of all stakeholders.

2. Background and Context

Regulation of investor-owned public utilities was originally instituted to address the natural monopoly provision of a necessary service. The technology of natural monopoly, however, raised vexing issues since competitive pricing—the hallmark benefit of competitive markets—implies financial losses for the utility removing any incentive to invest in the provision of services. The practical solution, barring social subsidies, imposed a break-even constraint on revenues for the utility. These two *seemingly* contradictory concepts are, in some sense, the crux of the story of regulation since its start: How does one institute a break-even constraint while pricing utility services properly?

Since the regulation of natural monopoly has the inherent contradiction between society's interest and the monopoly's need for sufficient revenue to support investment, a bargain was struck between society and the property owner. Indeed, it seems that this bargain between property owners and the public is a historic construct. The US Supreme Court decision in *Munn v. Illinois* sanctioned the use of state police powers to regulate private property by looking to the long history of English common law and finding that private property is not always private. When that property is dedicated to use by the public, the Court, quoting Lord Chief Justice Hale, found that such property becomes *affected with a public interest* subject to the standard of charging reasonable prices and providing adequate service. Public utilities, as a unique subset of private property owners, are subject to this *regulatory compact* explicitly.[1] Exactly *how* the contract is specified evolved through decades of regulatory proceedings and case law. After experimentation and endless debates over fair value, two foundational concepts emerged in the 1940s guiding the design of the break-even constraint implemented through the US Supreme Court's decision in *FPC v. Hope Nat. Gas Co*., (*Hope,* 1944). First, utilities are allowed recovery of *only* prudent investment costs to which a fair cost of capital is applied.[2] Second, no specific formula is required *but* the results must create rates that are not unjust and unreasonable.

In the following years, jurisdictions gravitated toward the use of historic cost to calculate test-year revenue requirement by applying the prudence standard to the capital deployed in the provision of service to achieve the break-even constraint.[3] The test year is a twelve-month period during which the costs of providing service are estimated. While utilities were never guaranteed any certain level of capital recovery in this break-even constraint, the test year approach created an expectation that, if the utility operated its business in an efficient manner, it would recover its test year capital costs, not on average, but in whole, since the break-even constraint must allow for full recovery of costs, at least on an *ex ante* basis. (*FPC v. Natural Gas Pipeline,* 1942; *Bluefield,* 1923). Investors and customers can then use this *reasonable expectation* of full cost recovery to make investment and consumption decisions.[4]

To commit the parties to this process of an *opportunity* for the utility to recover its full costs, the regulator is constrained from modifying the contract *ex post* through a general prohibition on retroactive ratemaking. (*See infra* note 28). The economic purpose of this rule is to maintain the balance between supplier and customer through the utility's incentive to manage costs while avoiding the regulator's inclination to reduce prices after-the-fact. From a regulatory perspective, the rule forces the parties and the regulator to fully examine all costs in the test year to assure that only those costs that are expected in the test year, though no less, are included in the test year revenue requirement. With these principles in place, this version of the break-even constraint represented an agreement with the supplier that the regulatory body would not take *ex post* actions that would *artificially* interfere with the utility's ability to recover its test year costs, and the utility could not request to include post-test year costs in the contract price. This process did not prevent customers from paying higher rates due to *unexpected* lower costs nor did it shield the utility from the risks of *unexpected* higher costs. Importantly, however, customers are expected to pay rates that recover the test year costs based on the presumption that the test year evaluation captured the entirety of those costs.

Yet prices are designed to reflect costs incurred in the *rate effective* period because that is when service is provided.[5] This seems to create a task nearly as difficult as the one *Hope* tried to solve—divining uncertain value—the uncertain value of future costs. Fortunately, under certain conditions, using yesterday's costs to project tomorrow's cost is often *close enough* that the regulatory process worked surprisingly well in the twenty-five years following *Hope*. McDermott (2012), and others, have called this the *Golden Age* of regulation since it coincided with strong economic growth, stable fuel prices, generally stable inflation, and continued productivity gains, which all led to falling real end-use utility prices.[6] Since then, as now, prices were primarily volumetric based, a substantial contribution margin was inherent in prices due the high fixed costs in the revenue requirement. Sales growth provided a cushion against misestimation of future costs. Even if historic costs were never a good estimate of future costs, incremental revenue from increasing sales offset the incremental costs ignored by the historic cost test year construct. Resetting of rates was not regularized and rate case timing was left largely to the discretion of the utility with some jurisdictions allowing regulators to order *show cause* cases if prices and costs became too disconnected. Yet these conditions that allowed the historic costs to proxy for future costs are not guaranteed to exist permanently.

By the 1970s utilities began to face a natural penetration limit in geographical spread and end user adoption of energy-using applications contributing to the decline in sales growth. In addition, rapid increases in fuel prices combined with government policies promoting energy efficiency fueled the longer-term response from consumers who began to adopt energy-saving technologies, fuel-switching behavior and, in the industrial sector, outsourcing. As a result, annual increases in electric and natural gas sales, which averaged in the high single digits in the years following *Hope*, began to fall in the 1970s and converged to the low to mid-single digits which remain today.

Falling sales placed pressure on incremental revenue whereas macroeconomic turbulence, initially from historically unprecedented inflation, then from productivity declines, and the requirement to maintain and expand the system with capital additions, placed pressure on incremental costs. With incremental revenues falling and incremental costs rising, *attrition*—the yearly decline in utility earnings—began to occur faster than utilities could file rate cases. In extreme cases, attrition reduces the utility's ability to raise capital to ensure future adequate service levels, violating the goals of *Hope*. With the assumptions that fueled the Golden Age rapidly giving way and the increasingly obvious misalignment between historic costs and future costs, the question of designing a new break-even constraint became more complicated and regulators began to experiment with alternative approaches to estimating future costs. (*See e.g.,* NYPSC, 1977)

While historic test year ratemaking often adjusts costs for known changes between the time the rate case is filed and the time rates go into effect, factors beyond those *known and measurable* changes, e.g., overall inflation and certain plant additions, are not included and can result in attrition which erodes the *opportunity* to recover the test year costs violating the regulatory bargain. One obvious solution is the *future* test year revenue requirement. In theory, no dispute exists that rates are set prospectively and that the test year is intended to represent the costs of providing service in that prospective period. A future test year representing, or better representing, the rate effective period seems like the perfect solution. The problem lies not in the theory *per se* but the reality of the regulatory structure. Historic data, for all its pitfalls, is auditable whereas future test years require projection of costs. With a future test year, the regulatory process becomes less of a cost discovery process and more of a modeling exercise. Moreover, stakeholders often suspect that utilities have the incentive to overestimate costs which makes detection of excess costs more difficult relative to an auditing exercise. (Costello, 2013).[7] This could tempt the regulator to adjust its decisions in the face of this uncertainty potentially causing a kind of *market for lemons* problem in which each side may recognize the value of the process but are unwilling to engage in an agreement due to the uncertainty. Indeed, early attempts to implement future test years were met with skepticism concerning both the veracity of forecasts and degree of attrition. Yet *attrition* in the context of the historic cost test year became undeniable. The future test year, nevertheless, represented a holistic approach to attrition resting on the principles of the historic test year by maintaining the *matching* of costs in the rate effective period with prices.

Attrition is often associated with *regulatory lag*. Regulatory lag is the time between cost increases and when costs are reflected in rates. This lag has potentially beneficial implications; to the extent that utilities can control costs, the lag improves profitability. To the extent that cost pressures are not under control of management the lag creates attrition. This led some regulators to the conclusion that creating an automatic adjustment clause ("AAC") better matches the cost increases with the period in which rates are in effect since full rate cases were too slow to adequately address the matching of costs and revenues. (*See e.g.,* Kaufman and Profozich, 1979). While automatic adjustment clauses had been in place since the fuel price inflation that occurred after World War I, those clauses were limited to fuel or gas costs and may have only applied to certain classes of customers. New AACs were proposed and implemented that addressed the entirety of costs based on an exogenous measure, such as the consumer price index, or a measure of utility earnings. Whatever the process, the intention remained to more closely match costs with revenues to allow the utility the opportunity to recover reasonable capital costs which, in turn, would allow access to reasonably priced capital ultimately benefiting consumers much the same way that regulation did during the Golden Age.

The incremental cost of service includes changes in operations expenses and changes in the cost of plant and equipment. Since the capital recovery portion of the revenue requirement is based on the historic costs of the plant and equipment used to provide service, capital cost inflation can raise attrition concerns separate from the change in overall expenses. Capital costs are related to the recovery of capital through depreciation charges and the return on capital paid to equity and debt investors. When capital costs and the scale of growth plus replacement exceed historic levels, the depreciation rates based on historic investment will typically fail to generate cash flows adequate to cover current and expected system investments. This form of attrition places pressure on finances for utilities facing growth and replacement programs. For the natural gas industry, this can be seen below in Figure 2 where accelerated capital investment programs nationally are correlated with difficulty in utilities earning their allowed returns. At the same time overall costs were increasing due to overall inflation, nominal increases in interest rates caused the cost of obtaining capital to rise substantially. Matters were further complicated since incremental capital costs were higher than historic levels leaving depreciation charges, in total dollars, on existing plant and equipment below the replacement costs. Adding in longer lead times on capital additions, especially in the electric industry, left many utilities with *phantom* short-term earnings in the form of promises of future cash flow by including funds used during construction in future rates. This led to proposals to include current financing costs in rates through allowing return on construction in process despite the obvious misalignment between used and useful capital and rates.

While costs matter to attrition, the second part of the story is the recovery of costs. As noted above, when sales were increasing the contribution margin inherent in volumetric prices balanced the increase in costs with increasing revenues with no need to explicitly address either in the post test year period. Indeed, one might expect to the extent that a future test year is used with normalized sales to set end use prices this might address both the revenue issue and the costs issue inherent in attrition. Two concerns are raised by this conclusion. First, like the future test year costs, future sales are uncertain and require forecasting. Concerns are once again raised about the incentive for forecasting bias. Second, by the early 1980s the government undertook a concerted effort to *reduce* sales explicitly through utility-sponsored rebate programs, local building codes, and pricing innovations. If regulators insisted on keeping substantial contribution margins in volumetric rates, utilities, it was argued, have the incentive to under forecast future sales during the rate case and encourage, or, at a minimum, not discourage sales in the rate effective period. The gas industry illustrates the effects of these environmental changes most clearly. The amount of gas sold per customer in the residential sector has fallen over the past thirty years, though these trends began much earlier. (Figure 1). If rates retain significant contribution margin while per customer sales fall, the implication is attrition. In addition, as capital expenditures begin to outpace depreciation this only adds to the attrition problem. Again, looking at the gas industry, since 2011 capital expenditures have exceeded historic values due to increasing replacement costs to bolster the safety of the system which leads to attrition as measured by the difference between authorized returns and the earned returns for gas utilities. (Figure 2)

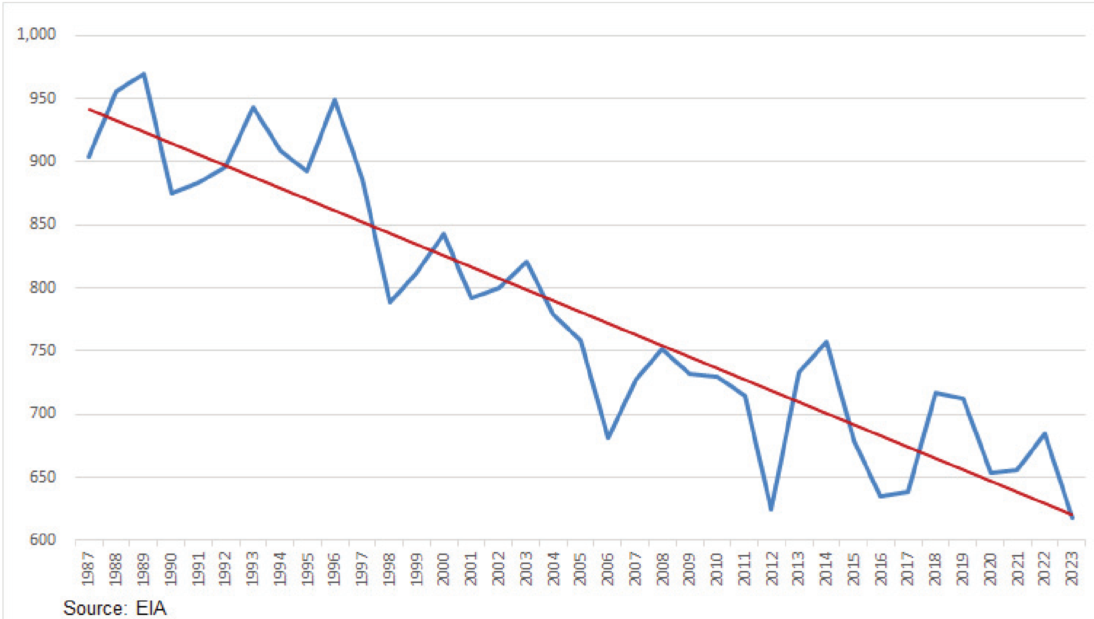

Figure 1: Therms Delivered Per Residential Customer (1987-2023)

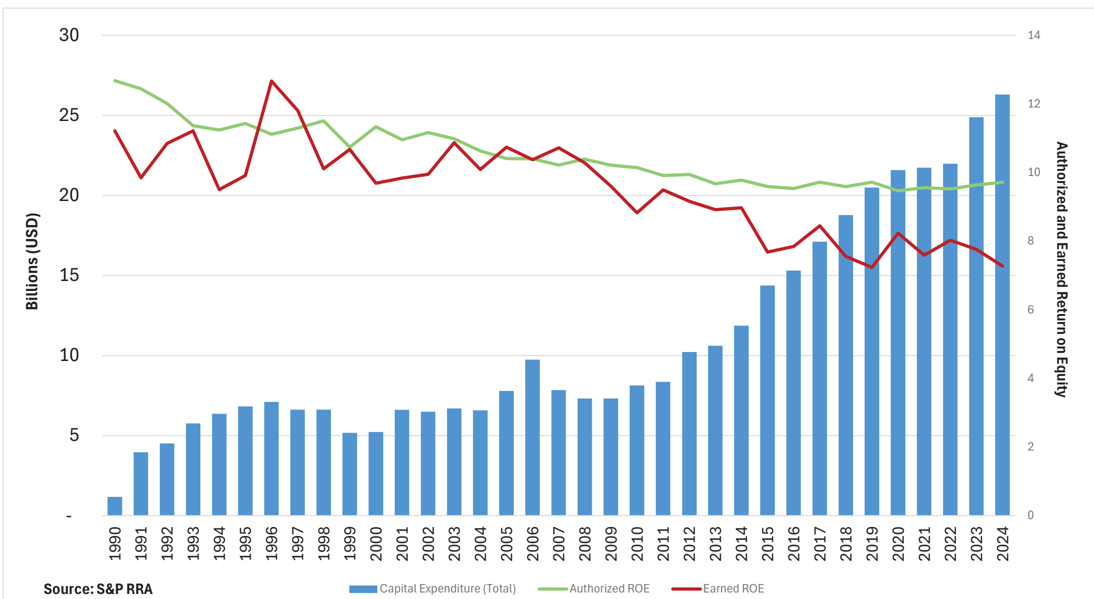

Figure 2: US Natural Gas LDC Capital Expenditures and Profitability (1990-2024)

The first incarnations of *post test year ratemaking* for non-fuel costs adjusted rates after or during the rate effective period to assure utilities retain the opportunity to recover costs in the face of uncertain sales.[8] This process is referred to as *decoupling* since the revenue recovered for service in the rate effective period is not dependent on sales, and, perhaps as importantly, sales projections. The simple version of decoupling compares the actual revenues earned with the allowed revenues in the rate effective period with any difference credited or charged to consumers. While this approach assures the revenue side of the equation is consistent with the intent of allowing the opportunity to recover full test year costs, it may work against this principle if the cost side of the equation is not considered. Decoupling usually includes a set of implicit or explicit attrition factors meant to proxy the incremental costs incurred in the rate effective period. Decoupling mechanisms may use revenue per customer as a metric for changes in costs or specific attrition factors to index expenses, changes in plant costs, and the financial capital costs. Whatever mechanism is used, however, the goal is the same: implementing a break-even constraint that balances the need for sufficient revenues for investment while maintaining just and reasonable prices.

As a result of changes in the operating environment of utilities and the growing concern over increasing prices, regulators began to experiment with regularizing the review of costs through rate case cycles. Instead of the traditional approach of leaving the choice of initiating a rate review to utility management, rate case cycles were instituted to ensure that rate reviews occurred often enough to maintain the connection of costs to prices. While some jurisdictions simply required a traditional rate case review on a regular schedule, others, most notably, California, created a process that provided for rate changes during periods between regular rate reviews. What later became known as multi-year rate plans ("MRP") effectively created a multi-year test year by allowing changes to non-fuel base rates during the pendency of the plan. MRPs seemingly offered a solution to the design of the breakeven constraint by setting prices over an extended period based on projections of future costs though with safeguards to assure that forecasting errors, whether about sales or costs, were corrected through the process. MRPs also hold the promise of lowering prices and improving quality of service through more frequent review of utility investment and operations while providing the utility with some degree of certainty that the opportunity to recover capital costs would remain. Generally, MRPs have common features that attempt to replicate the features of traditional one-off rate reviews by adhering to general principles laid out in *Hope*. MRPs do recognize that rates are set prospectively but do not alter the uncertainty concerning forecasts. This is often addressed through a true-up mechanism that provides a guardrail against mistaken forecasts. MRPs also provide for attrition factors for both expenses and plant additions. Since plant addition forecasting is a budgeting process, rather than a statistical or econometric process, ordinarily separate attrition factors are used for plant additions and operations expenses. Operating expenses are usually easier to forecast since the relationships are more regular. As a general principle, expenses should change over time based on the overall rate of inflation less productivity gains. If productivity gains are relatively small, which is likely in mature industries like utilities, the overall rate of inflation should be sufficient as a proxy for expense changes.

Capital additions, however, are less easy to predict largely because capital is both an expense and an investment. The expense associated with capital is called depreciation and measures the use of capital in any given period. From an accounting perspective, utilities are generally required, for ratemaking purposes, to depreciate capital on a straight-line basis. From an economic perspective, straight-line depreciation likely does not coincide perfectly with the actual use of capital over time. One reason is the difference between the valuation process for ratemaking—historic depreciated cost—and the current cost of replacing capital. Capital is also an investment which provides services over several years, often decades, making planning for capital additions less certain in the sense that the cost of replacing existing capital, or the need for new capital investment, may have little to do with the existing cost of capital on the books of the utility. Moreover, capital often wears out faster than expected, sometimes due to exogenous factors such as climate and weather changes, or human error such as third-party accidents. Since capital provides service over the long term, planning for capital additions is more complicated than budgeting for expenses. For example, in general, no utility wishes to wait until its equipment breaks down to replace or maintenance the equipment. Indeed, nearly all utilities operate under a legal requirement to provide adequate, reliable, and safe service during differing demand conditions. Since this obligation requires utilities to stand ready to serve under all conditions, some judgment is required as to exactly when to replace old equipment and prudent management can accelerate or defer capital investment based on the operating conditions and environment. This provides flexibility to management in choosing the timing of capital expenditures but also requires replacement when aging equipment nears end of useful life no matter what economic conditions the utility might face (e.g., high interest rates).

In the Golden Age of regulation, designing the break-even constraint was, in some sense, a simpler task since the economic conditions were conducive to the simpler approaches. As economic conditions changed, re-establishing the balance in the breakeven constraint required more explicit recognition of the factors that affect the balance between providing customers with reasonably priced services and providing the opportunity for the utility to break even on its investments. Reduced sales growth affected the revenue side of the equation while inflation, and later productivity declines, along with the obligation to serve affected costs. Decoupling mechanisms addressed the revenue side by placing an emphasis on target revenue recovery, while attrition factors addressed the costs by linking rate increases to verifiable indices and prudent investment streams.

3. The Balance: Implementing the Regulatory Compact through the Rate Case

> The rate-making process…the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests…regulation does not insure that the business shall produce net revenues…But…the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. (*Hope,* 1944)

That a compact or, indeed, implied contract between the state and the regulated entity exists has its roots in the understanding that some services are of such importance to the public interest that government has a duty to supply these services.[9] Yet government may not have the requisite expertise or inclination and providing services may require substantial capital outlays that private entities will only provide given certain privileges that protect that capital. This *meeting of the minds* represents the regulatory compact.[10] It is difficult to read any state public utility law which does not define both the obligations of the regulated entity and its rights.[11] The regulatory compact is a *quid pro quo* of the granting of the monopoly in return for the truncation of property rights through public regulation.[12] That the contract is not set in stone as to its construction is also of no doubt. Obligations and rights may change over time, expanding or contracting, yet the existence and guidance of the compact remain. (*See e.g.,* Goldberg, 1979, pp. 14-15; Dasovich, Et al. 1993. pp. 9-14)

Under these conditions, it is the institution designed to manage the relation that is of paramount importance. The legal obligations involve a strange combination of volition and compulsion: the right *to be served* and the right *to serve* both flow from the relation created by the economic position occupied by the public service company ordained by society. (*See e.g.,* Glaeser, 1927; Goldberg, 1979). Investors choose to invest in the public service entity and consumers choose to take the services under the terms and conditions approved by society and administered by a regulatory agency.[13] The idea of contract permeates this relationship, generally in the form of legislation and tariffs that identifies the terms and conditions of sale and purchase. As with any contract, or bargain, the terms of the contract apply to each side.[14]

Regulation of public utilities, then, more closely follows a *relational contract* in which longer-term interaction occurs between parties and adaptation of the contract to new events, contingencies, and policies occur. (Goldberg, 1976). The lens of contract provides a useful construct to analyze the regulatory structure which can incorporate uncertainty and is conditioned by exogenous changes such as policy, competition, and technological evolution.[15]

Conceptualizing the process as the administration of a relational contract focuses the analysis on the necessary adjustments of the relationship to address exogenous technical, economic, and financial shocks. It is a *constitutional* problem of balancing the risk-taking by investors who provide funding for the long-lived highly capital-intensive assets with the needs of customers who depend on the services provided by those assets. (Goldberg, 1979, Zimmerman, 1988). Long-term contracts are one potential governance structure, though the complexities and uncertainties inherent in the provision of utility services, from, for example, unknowable future demand conditions or future public policy, has led to the substitution of regulation for the contracting process.[16]

Whether this regulatory compact is a legal contract in the technical sense or if it reenforces the incumbent's advantage is immaterial.[17] The obligations and rights under the compact are ordinarily defined by legislation, case law, and customary practice.[18] Indeed, the foundational administrative process, the rate case, is largely a creature of primary and secondary legislation, along with regulatory and legal precedence.

A rate case is the administrative mechanism used to adjust the pricing of the regulatory contract over time. Traditionally, the rate case was the *only* process by which rates were adjusted since it allowed for discovering and reviewing the entirety of costs in the test year.[19] As noted above, however, conditions changed such that the rate case mechanism, while still the primary process for developing prices, evolved into the process by which prices remain tethered to costs and regulators monitor the performance of the utility in delivering service.

While the standard objectives of safe, reliable, and affordable service remain the basic objectives, as societal goals changed specific requirements of the utility also changed. Efficient operation, traditionally left in the hands of utility management, became least-cost service. The obligation to serve under any demand conditions has evolved into requirements to modify demand through, among other policies, customer-financed energy efficiency programs. Initially these programs were simply designed to substitute for higher cost provision of service, but they began to evolve into specific requirements to address the external costs of the provision of energy services. Performance standards are now commonly incorporated into the regulatory process much as a liquidated damages clause in a commercial contract. The regulatory contract implies that obligations—benefits to one side of the bargain and costs to another—are properly accounted for through modifications to the price setting process.

One issue facing any administrative regulatory mechanism is time. Obligations to serve customers, now and in the future require periodic investments necessary to supply those services potentially occurring under different sets of market conditions. The accuracy of demand forecasting, even without potential bias, depends on how far in the future prediction is required. Traditionally, regulators and courts took a dim view of including hypothetical, uncertain, remote, and conjectural costs. (*See e.g., Los Angeles Gas and Electric Corp.*, 1936). While modern statistical methods, data collection technology, and regulatory oversight have improved, periodic true-ups and the use of balancing accounts are used to ensure that the regulatory framework is robust to potential errors.

Time is also a critical element in exogenous events. Shocks to demand, supply, financial markets, technology and resource availability, as well as recognition of environmental aspects of technologies can all have an influence on the flow of cost over time. Regulators, in some sense, face a set of contradictory elements in the design of an administrative process to address the forces inherent in time as it appears in different elements of the process.

Regulation has, from its start, the goal to mimic competitive results.[20] Yet this desire also reflects temporal contradictions. Market prices can, and often do, change instantaneously, or at least often, to reflect changes in costs and demand. Regulation is, for the most part, unable to assess whether frequent price changes are due to fundamental economic conditions or market power and the regulatory process has incorporated less frequent price changes. Moreover, incentive aspects of competition impose the discipline of the market to control costs. With competition largely absent, regulators wished to design a process that might replicate the incentives to maintain efficiency.[21] By changing prices less frequently, some of the efficiency aspects of competition are replicated through the administrative process.

The central principle in establishing an administrative pricing process under public utility regulation is to find the actual prudent costs of service to create just and reasonable rates recognizing that timing of the rate and cost changes are important to maintaining the balance required by the implementation of the regulatory contract.

4. Timing and The Rate Case Framework: Implementing the Balance

The cost-of-service regulation ("COSR") framework employes a test year that serves as the foundation for setting rates by establishing the relationship between costs and revenues to assess the actual earnings situation of the company. The COSR framework represents an attempt to create a comprehensive system to calculate the legitimate total prudent costs of supplying utility service as a mechanism to implement the regulatory compact.[22] Under this system, a *total revenue requirement* is determined based on the total cost of supplying services, including capital costs.[23] The approach is summarized in Figure 3.

$$TRR = TC = [RB - D]\ ROR + OE + d + T$$

TRR = total revenue,

TC = total cost, RB = rate base or value of capital

D = accumulated depreciation

ROR = weighted average cost of capital equals the cost of equity (profit to owners) multiplied by the percent of equity used to fund the firm plus the cost of debt (average interest rate paid on bonds) multiplied by the percent of debt used to fund the firm

OE = operating expenses

d = annual depreciation cost

T = taxes.

Figure 3: Regulatory Equation

The history of regulation has been a struggle to define how this equation and its elements are interpreted and applied. The problem facing regulators was how to operationalize a concept based on this highly theoretical construct. What standard should be employed? Should it be the competitive model? In the competitive model an equilibrium occurs when total average cost equals average revenue or total costs equal total revenues. Whether by design or accident, the COSR method has evolved into a process that mimicked the long-run competitive equilibrium price resulting in the total revenues covering long-run total costs, inclusive of the opportunity cost of capital.[24] The use of a test year was employed to simultaneously match the cost and revenue in a specific time frame. [25] This "stopping of the film" ensures that the regulator understands the relationship between cost and demand conditions. (*LS Ayres & Co.*, 1976). If costs exceed revenue, then a rate increase is necessary. Likewise, if revenues exceed costs in the test year a rate decrease is warranted. This balance between costs and revenue yields the revenue requirement which is the amount of revenue needed in the rate effective period to provide services at the assumed basic level of reliability under normal operating conditions.

Under this *equilibrium principle*, the evaluation assumes that the total prudent and reasonable costs of service are identifiable.[26] Within a rate case, the regulator's role in protecting consumers must include the ability to review all costs and disallow those costs deemed unnecessary or imprudent. The Court even noted that this is part of the regulatory bargain when the sovereign grants a privilege to a property owner and that grant is only justifiable if the regulator has the authority to execute its duties to judge appropriate cost levels.[27]

This conceptual framework implies that "current and foreseeable future costs of furnishing the service must be covered" and that "*fair and reasonable* rates…make it economically feasible for the public utility, under efficient management, to meet all costs of furnishing services and to otherwise comply with the statutory obligations imposed upon it." It is the "essential task…[of the regulator]…to determine…the present and foreseeable future…costs…And…to achieve a condition of equilibrium between unit rates and unit costs…otherwise described as a condition of *zero* economic profit for the public utility whereby all economic costs of furnishing services, including the cost of the capital invested, are covered by its revenues and neither positive nor negative difference or 'profit' results. . . ." (*Re Public Service Company of New Mexico*, 1974)

To operationalize the total cost-equilibrium framework, regulators adopted the test year, though one potential drawback to this approach is it reflects a static view of the equilibrium framework. In a competitive market if exogenous factors do not change then the equilibrium price does not change but if those factors do change the price changes. Regulation using the equilibrium principle assumes the former as the ordinary course of business. When this assumption is incorrect, regulation adapts. In summary:

> …the dual nature…of proper rate making…enable[s] the public utility (1) to meet all costs of furnishing services and (2) otherwise comply with the statutory obligations imposed upon it…Under less volatile…conditions…where current service rates equaled current service costs and moderate increases in the latter could be offset by increased operating efficiency…the ability of public utilities to satisfy growing demand and to maintain and improve the quality and reliability of their services was not impaired…Momentary equality between fixed service rates and service costs, even with automatic adjustment of service rates to cover increasing fuel costs, does not assure than an electric utility will be able to discharge its service obligations to the public in the long-term or even the moderately short-term, future. Respecting energy utilities, three principal phenomena are responsible for this circumstance--namely, (1) rapid inflation in virtually all unit costs of service, (2) growth in demand for services, and (3) growth in capital intensity requirements. (*Re Public Service Company of New Mexico*, 1975)

Setting rates is only one part of the process, assuring that exogenous events do not disrupt service provision is the second part and that may require attention to post-test year changes in the operating environment. Indeed, the "rate base, expense and revenue data for an historical test year are meaningful…only insofar as past operations are representative of probable future experience." (*LS Ayres & Co.,* 1976)

There are several observations relevant here. Time—or more precisely exogenous factors affecting costs over time—is a central issue. Do the test year data provide an accurate representation of the rate effective period? Do these data, even if projected, capture the totality of the costs of serving customers? Does the data provide a complete picture of the relationships between investment and operating costs? The use of a test year implies some lag embedded in the data. That is, if costs are static or not subject to volatility the lag incentive can help hold costs down. If not, then attrition occurs whether the test year is forecasted or historic, though likely more significantly in the case of historic test years. The incentive created by regulatory lag is an artifact of the *filed-rate doctrine* combined with *prohibition against retroactive ratemaking* that creates regulatory lag.[28] (*See e.g.,* Hall, 1983)

By focusing on the total cost in constructing the break-even constraint the regulator focuses on creating a type of *earnings test* by comparing revenue in the test period with the expected costs. This includes the cost of repaying investors such that the utility can raise capital to finance the utility on an on-going basis. This synchronization of cost and price through the test year has, for nearly the entire history of public utilities, been augmented by adopting mechanisms allowing revenues to track cost changes over time to maintain the breakeven constraint. Fuel adjustment clauses and purchase gas adjustment clauses provided for a more formulaic mechanism for cost recovery without the expense of a review of costs in totality. (Trigg, 1958). The critical issue in any case employing a formula is that the data employed accurately reflects the underlying cost changes. The fuel adjustment clauses were able to pass this test and were not *automatic* in the sense that prices were adjusted without review, though often that review will occur after prices are set using a refund mechanism.[29] (*See e.g.,* Kelly Et al., 1979; Foy, 1960)

The regulatory process has, in effect, established a budget constraint for utility management. Given the assumption of normal fluctuations and normal prudent management, the utility should reasonably operate within this constraint. Once, however, large and volatile cost fluctuations occur with little or no managerial control then the regulatory imposed budget constraint no longer represents a reasonable constraint, and the utility is forced into decisions that could have negative impacts on customers. Because the utility has an obligation to serve, it must incur costs to serve customers even if it has no method for resetting prices. As a result, trade-offs are imposed on management that may require deferring capital expenditure or reducing non-revenue expenses that are under management's control, but which may have long-term, or even short-term, implications for service quality. What normally occurs, however, is the utility, recognizing its obligation to provide adequate services, will bear the burden of these cost changes by accepting a lower return than is approved and reasonable. While forcing shareholders to provide service below cost may seem like a way to strike the balance, it is not, since regulators are required to

> …fix service rates at levels that will enable the public utility to recover its costs of furnishing the service, including a fair rate of return to or the cost of the invested capital actually and necessarily involved in the furnishing of such service. Up to that point, the public and consumer interests are not material and cannot be considered… (*Re Public Service Company of New Mexico*, 1974.)

Only past the point of setting rates at cost, including a reasonable cost of capital, does the consumers' interest takes precedent over the investors.

5. Addressing Timing: Reestablishing the Balance

Since utilities are required to plan for all future demand, there are several sources of uncertainty: (1) demand may fail to materialize as anticipated; (2) investment tends to require significant lead time; (3) projects usually require large up-front capital requirements; (4) some investments are *lumpy*; (5) nearly all utility investment is relation-specific in the sense that it has no alternative use. The regulatory contract addresses these issues by providing a method of cost recovery for all prudent investment including those that are prudently abandoned or cancelled because of unforeseen events (e.g., unrealized demand growth, technological change, excessive input price inflation, etc.).[30] Recovery of prudently abandoned investment is often amortized with, or without, full carrying costs of the unamortized balances. (Zimmerman, 1988; Rodgers and Gray, 1985)

The issue of attrition has also occupied regulators' attention since the dramatic inflation of the 1970s which stressed the process of maintaining a breakeven level of revenues. The Arizona Commission noted:

> Attrition does exist. In essence, company earnings are subject to erosion over time. While the effect of this phenomena may be minimal in some and possibly even most utility operations, the impact of attrition on a billion dollar plus company can be sizable. Earnings are based upon a test period which, though it be adjusted and modified, is still to some extent a model based upon a past period with historical costs and revenues. Time does elapse from the end of that period and those calculations until the entry of an order by the commission. Over that period of time any rate of return set by the commission on the test period will erode. To what degree is the difficult question. (*Re Arizona Public Service Company*, 1980)

The California Public Utilities Commission recognized during an inflationary period that there was a need to employ alternative methods to enable revenue to more effectively track cost changes. The adoption of a revenue adjustment mechanism helped to reestablish this balance:

> …Through the application of a revenue adjustment mechanism, rates are changed to reflect the difference between authorized and recorded sales levels. The utility is afforded a better opportunity to earn its authorized rate of return during the test year and the attrition year. The ratepayer is, in turn, afforded protection, because the mechanism ensures that the utility retains no more than the authorized amount of base rate revenue. Furthermore, the adoption of a revenue adjustment mechanism is effective in eliminating disincentives for the utility to promote the conservation and rate design policies enunciated by this commission. (*Re Southern California Edison Company*, 1982)

These concerns were not new.[31] Some argued that adoption of fuel or purchase gas clauses represent an abdication of regulatory authority, but courts generally rejected those claims:

> The proposed escalator clause is nothing more or less than a fixed rule under which future rates to be charged the public are determined. It is simply an addition of a mathematical formula to the filed schedules…… under which the rates and charges fluctuate as the wholesale cost of gas to the Company

> fluctuates. Hence, the resulting rates under the escalator clause are as firmly fixed as if they were stated in terms of money. (*City of Chicago*, 1958)

These mechanisms were necessary to maintain the financial integrity needed to obtain funds to provide continuous service to meet customers' needs and meet the utility's obligation to serve. One of the central focuses of the regulatory process was to ensure society received the services necessary to support the economy, the utility was given an opportunity, but not a guarantee, to earn a return on its investment. The Courts in turn have employed earnings tests to judge the severity of any financial harm or impairment, when deviations from the breakeven constraint occur. In a decision on the cancellation of Jersey Central's Forked River nuclear plant, the Court tried to sort out the issues, noting:

> …Hope Natural Gas talks not of an interest in avoiding bankruptcy, but an interest in maintaining access to capital markets, the ability to pay dividends, and general financial integrity. While companies about to go bankrupt would certainly see such interests threatened, companies less imminently imperiled will sometimes be able to make that claim as well…The contention that no company that is not clearly headed for bankruptcy has a judicially enforceable right to have its financial status considered when its rates are determined must be rejected. (*Jersey Central Power*, 1987)

According to the court, "[u]nder Hope ... the only circumstance under which there is a possibility of a taking of investor's property by virtue of rate regulation is when a utility is in the sort of financial difficulty described in Justice Douglas' opinion…[the regulator then]…must inquire whether a reasonable return—on investment, not on facilities—has been afforded to investors, taking into account whether any higher return would amount to exploitation of consumers." (Id.) Without financial hardship there can be no illegal taking of property and it is the earnings, not the property that is of import to the evaluation.

Operating expenses would seem more straightforward in their relationship to service since those are usually directly related to current services. Yet wage contracts are often negotiated for specific time periods longer than a test year and may incorporate adjustments. Other contracts may extend over multiple years with the idea of minimizing long-term costs for a flow of services over time. Even interest expenses may relate to the term of the borrowing. Time, that is, operational environmental changes after the test year, permeates all aspects of the public service firms' operations. The test year is but an administrative construction for approximating the prudent costs of providing the flow of services and setting prices on a prospective basis. Once costs have been identified the next step is to control for abnormal events. Normalization is made to recognize that prices should reflect costs on a prospective basis during rate effective period. Normalization involves adjustments to eliminate the effects of nonrecurring expenditures and events. Often this process investigates past records to develop an expense profile used to project test-year expenses. Normalization may also recognize patterns that are known to have changed from past patterns such as labor or services contract escalations. Normalization, in the context of a historic test year, is distinguished from forecasting in that the normalization process is not a forward-looking exercise. Even with normalization and adjustments for known changes, regulatory agencies rely on data that is, at best, current as of the hearing date, however, more often, many months or even years out of date. Expected revenues are also often, but not always, normalized to estimate a test year return. Normalizing revenues usually means normalizing weather conditions to adjust for any abnormal conditions that might exist during the test year.[32] Future test years are forward-looking in nature. In rejecting a proposed test year that included an estimate of operations extending six months into the future, the Connecticut Commission noted:

> …We are cognizant of the difficulties encountered by an applicant in attempting to select a proper test period for use in portraying the company's need for rate relief. Actual figures, while unquestionably accurate, reflect historic events, whereas rates must be established prospectively. The ideal situation would be one wherein results of future operations could be ascertained with unquestioned accuracy. (*Re Southern Connecticut Gas Company*, 1969)

Capital equipment is usually selected to provide the lowest possible flow of costs over time at the time the choice to invest is made. That choice prospectively considers expected future customer demand. The mix of equipment reflects the characteristics of that demand such as the timing and duration. Since utility services are delivered on a continuous basis, that requires a continuous, and in some cases even instantaneous, balancing of supply and demand. Flipping the light switch, turning on the water tap, or turning up the thermostat changes the demand on the system. Poor planning for these changes in demand may create poor quality of service, or even outages, causing societal costs since customers make investment decisions assuming performance under the regulatory contract.

When stress on capital recovery confronts capital needs, regulators regularly recognized the intimate links between the design of the regulatory compact and the public interest. Consider the response in Maine:

> The experience of recent years shows that, as construction budgets and financing costs rise, strict adherence to the matching principle may be achieved at the cost of rates that are higher than would otherwise be necessary. Thus, a utility with a large amount of plant under construction, which generates only non-cash earnings pursuant to the matching principle, may find that access to capital to continue construction may only be had on terms less favorable than those extended to a utility with smaller capital requirements or larger cash earnings. Were the commission to be faced with such a situation, it would have to assess the comparative costs and benefits to ratepayers, investors, the utility, and the public interest of adhering to the matching principle and the construction program in the face of rising capital costs, or of deviating from either the principle or the program to some degree in order to preserve the financial integrity of the utility. Thus, were the commission to conclude from the evidence before it that continuation of its policy denying a current cash return on CWIP would have a substantial adverse effect upon the utility's financial condition in the face of a necessary construction program, it might well alter that policy to the extent necessary to prevent the harm and to assure that needed plant could be built on reasonable terms. (Decision in *Central Maine* quoted in *Re Bangor Hydro-Electric Company*, 1982)

The various treatments of cost that evaluate the timing and incurrence can be illustrated by a discussion in a New York state planning case. In the NYPSC order, the Commission discussed the hearing examiners' characterization of the choice between AFUDC (accumulating financing costs of new construction for recognition in a future rate case) and recognizing construction work in process (CWIP) in a current rate case illustrating the complexities in addressing the timing of recovery as a policy matter:

> Arguing in favor of the AFUDC policy is the notion that the financial charges applicable to a particular project should be recovered solely from customers taking service after the project is completed and the facilities are in use. Under this reasoning, CWIP in rate base is undesirable inasmuch as it inequitably forces ratepayers to pay financial charges on plants still under construction. But in order to accept this analysis…one must assume that plant under construction does not serve current customers…most ratepayers are not just current period consumers of electricity, but are placing "economic reliance on the continuous provision of electricity now and into the future, without regard to the timing of generation or transmission facility additions by the utility."… attempts to "compartmentalize" ratepayers in terms of the benefits of service provided by particular facilities is a "bogus exercise" inasmuch as the benefit customers actually receive is continuous service over time. Moreover, said the judge, even if customers are analyzed in terms of a particular facility, the vast majority of customers taking service during its construction are likely to remain on the system after the facility goes on line; consequently, "today's ratepayers and tomorrow's ratepayers, to no small degree, are the same customers. (*Generic proceeding investigating financing*, NYPSC, 1982)

The public interest that is protected by the regulatory compact is complicated by the pervasive intertemporal aspects of providing services over time. Attempts to compartmentalize the elements of service when capital is long lived, and operating costs fluctuate, leads policymakers to adopt mechanisms that track costs and adjust prices on a more real time basis to avoid the serious mismatches between cost and revenues.

Timing of when costs occur matters to the implementation of the regulatory compact. For virtually the entire history of regulation when sales do not increase as expected and input prices are volatile, attrition matters more as illustrated by the long history of using automatic rate mechanisms. In the last decade, regulators have recognized that timing matters to attrition and have implemented numerous mechanisms to reinstate balance to the process of rate setting. These mechanisms have various names, including price caps, revenue caps or decoupling, multi-year rate plans, formula rates, and various mechanisms associated with these plans, or separate from these plans, such as capital cost trackers, performance incentives, and specific rider mechanisms to recover mandated costs (e.g., energy efficiency spending) and material costs outside the control of the company. Fundamentally, the mechanisms are designed to provide a better connection between the prices customers pay and the cost incurred to provide those services. Attrition mechanisms, whether specific, such as inflation indices for operating costs, or projected, indexed, or otherwise adjusted capital costs are designed to proxy the changes in costs that would have been included in the test year had those cost been perfectly forecastable *ex ante.*

Research suggests that the most common specific attribution mechanisms are those with specific expense indices, usually tied to a measure of inflation perhaps adjusted for productivity changes and a capital adjustment that is tied to estimates of historic or future capital expenditures. (Lowry, Et al., 2024). For example, a two-year MRP was approved for Avista, including the gas utility, in late 2024. The claims of some intervenors that the forecasted MRP was unverifiable were rejected in favor of the *Hope balancing of interests* argument. (*Washington Utilities and Transportation Commission*, 2024. ¶357, p. 96). This MRP uses forecasted expenses and capital for the two-year program which translated into an *ex ante* revenue increase for the two years of the program. (Id. ¶868, p. 230). A similar approach was used for Baltimore Gas and Electric in Maryland and National Grid in New York. (*Baltimore Gas and Electric Company*, 2023; *Niagara Mohawk Power Corporation d/b/a National Grid*, 2025).

These are just examples of the approach used to maintain the balance required by *Hope* and these examples illustrate that capital spending and expenses do not necessarily escalate at the same rates and require separate treatment.

6. Conclusion

The challenge of designing an administrative process that attempts to replicate the incentives of competition and balances the interests of multiple stakeholders is daunting. In addition, public service companies make long-term relationship specific investments to deliver services over time. In setting rates prospectively, the influence of environmental changes over time and the risks and uncertainties that come with the need to anticipate demands of customers presents significant challenges to ensure that the utility achieves the breakeven condition employed when setting rates. In the United States, regulation has focused on discovering the total prudent cost of delivering services to consumers and setting the revenues equal to that amount inclusive of a normal profit or fair return. History has shown that the vagaries of inflation, fluctuating interest rates, business cycles, and other exogenous factors, present major challenges to achieving the breakeven constraint.

This paper has examined several innovations that state regulators have adopted to address the problem of attrition that arises as history unfolds and estimates do not track costs accurately. Regulators have adopted adjustment clauses, multi-year planning processes, true-up mechanisms and other methods to attempt to better track the actual prudent costs of service to achieve the balance of interests. These mechanisms fundamentally preserve the opportunity of the utility to earn its allowed returns but more importantly to finance the system's continued operations to meet its obligation to provide necessary services to consumers.

Regulators have recognized that the fundamental intertemporal nature of the obligation to serve required the adoption of more dynamic adjustments to the traditional snapshot test year approach. Forward looking test years or forecasted test years face a similar dilemma as historic test years snapshots. While the equilibrium concept and the breakeven constraint are effective administrative ideas to help structure an approach to identifying the costs of service, these constructs cannot overcome the reality that costs and demands do not obey administrative precepts. Recognizing the inevitable, regulators have confronted the problem head on by developing more dynamic adjustments to the cost-of-service method of regulation to ensure customers receive services over time and utilities receive the revenue necessary to finance service provision.

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Endnotes

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[1] Cox (1932, p. 140) states the transformation from implicit to explicit regulation as follows:

> Under the common law those engaged in public callings were required to furnish reasonably adequate service and facilities. Statutory regulations have superseded the common law and, taken over that legal standard; also, regulatory provisions relating to specific matters of service have been enacted. Administrative commissions are charged with enforcing specific legislative requirements, and are given a discretion only in regard to the application of the general standard. The general and special provisions of these statutes, relating to public utility service, gives the commission complete power over the subject. Service and rates are very closely related. Commissions have the power to require adequate service only in case of a proper return; it cannot, under the guise of regulation, require a utility to expend large sums of money for the extension of its service into a new territory when the necessary result would be for the corporation to use its property for public convenience without just compensation.

[2] The *prudent investment* standard supplemented the *fair value* standard. *See* Justice Brandeis Opinion in *Southwestern Bell Telephone Company v. Public Service Commission of Missouri (*Justice Brandeis concurred on reversal but dissented on the fair value rule of *Smyth v. Ames* in favor of the prudent standard rule.). The standard of proof for prudence is the reasonable manager standard. The utility's actions and decisions are only judged based on their merit given the information available at the time. Specifically, an action or decision is imprudent only if no reasonable manager would have taken that same action or made that same decision. Imprudence is not established by substituting one's judgment for the judgment of the utility management. The prudence analysis must be done without the benefit of hindsight—whether the results of a decision are later shown to have increased costs is not relevant. Finally, careful analysis is necessary. Any analysis must recognize both the costs and the benefits of any action taken and requires an analysis of facts, not merely opinions or allegations. (*See e.g.,* FERC Opinion No. 544, 2015 (summarizing prudence approach), *also see New England Power Company*, 1985)

[3] By 1947 approximately twenty states reported the use of valuation methods that were more specific than fair value (e.g., original cost, prudent investment, or fair value methods that approximate original cost). (Federal Power Commission, 1948, Table B)

[4] Customers make capital outlays on energy-using applications with the expectation of adequate, reliable services at a cost-based price over the long term. The regulatory compact provides the balance for customers and investors to undertake long-term investments that involve sunk costs. (*See e.g.,* Goldberg, 1976; Biggar, 2009).

[5] The rate effective period is ordinarily considered the first twelve months the rates are in effect..

[6] Tomain (2014, p. 479) discusses the Golden Age in the electric industry. Natural gas interstate production and transmission was an exception to the Golden Age hypothesis. (Breyer and MacAvoy, 1974)

[7] It seems more likely that the utility would practice this behavior if the ratemaking process were a one-time game. The ratemaking process, however, is a repeated game where past mistakes can influence current decisions.

[8] The first decoupling plans were created for the gas distributors in California in the late 1970s due to the volatility of revenues associated with new rate designs, weather, and supply disruptions. (*See Establishing Supply Adjustment Mechanism*, CPUC, 1978)

[9] The Wyoming Public Service Commission notes the long history of this compact:

> [The]…Commission notes that a public utility, by its very nature, enters into a century-old compact whereby the state sets rates that permit the utility to provide safe, adequate and reliable service at a just and reasonable price while, at the same time, provide a reasonable opportunity to earn its authorized rate of return and attract new capital. (*In the Matter of the Application of Pinedale Natural Gas, Inc.*, 2015, ¶50, p. 12)

More recently, in discussing possible changes in the natural gas industry, the Massachusetts Commission noted the continuation of the regulatory compact as a guiding principle:

> As we chart the path for this transition, we emphasize that nothing we do here is intended to jeopardize the rate recovery of the billions of dollars of existing investments in natural gas infrastructure by the LDCs operating within the Commonwealth. Traditional notions of the regulatory compact continue to apply to those investments and, accordingly, there generally must be some demonstration of imprudence before recovery of existing investments can be challenged. At the same time, however, it is fair to say that a different lens will be applied to gas infrastructure investments going forward. The Department will be examining more closely whether such additional investments are in the public interest, given the now-codified commitment toward achieving Commonwealth's target of achieving net-zero GHG emissions by 2050 and the urgent need to address climate change. (*Order on Regulatory Principles and Framework,* Massachusetts D.P.U, 2023, p.14)

[10] From the US Supreme Court:

> …that the objects for which a corporation is created are universally such as the Government wishes to promote. They are deemed beneficial to the country, and this benefit constitutes the consideration, and in most cases the sole consideration for the grant.' The purposes to be attained are generally beyond the ability of individual enterprise, and can only be accomplished through the aid of associated wealth. This will not be risked unless privileges are given and securities furnished in an act of incorporation. The wants of the public are often so imperative, that a duty is imposed on Government to provide for them; and as experience has proved that a State should not directly attempt to do this, it is necessary to confer on others the faculty of doing what the sovereign power is unwilling to undertake. The legislature, therefore, says to public-spirited citizens: 'If you will embark, with your time, money, and skill, in an enterprise which will accommodate the public necessities, we will grant to you, for a limited period, or in perpetuity, privileges that will justify the expenditure of your money, and the employment of your time and skill.' Such a grant is a contract, with mutual considerations, and justice and good policy alike require that the protection of the law should be assured to it. (*The Binghamton Bridge*, 1865)

[11] For example, the Illinois Public Utilities Act (220 ILCS 5) sets out the goals and objectives for regulation including efficiency, equity (fair treatment of customers and investors), recovery of capital costs, and that regulation should not unduly affect utility earnings.
[12] The Supreme Court of Indiana described the regulatory compact as the "bedrock principle behind utility regulation" which

> …arises out of a "bargain" struck between the utilities and the state. As a *quid pro quo* for being granted a monopoly in a geographical area for the provision of a particular good or service, the utility is subject to regulation by the state to ensure that it is prudently investing its revenues in order to provide the best and most efficient service possible to the consumer. At the same time, the utility is not permitted to charge rates at the level which its status as a monopolist could command in a free market. Rather, the utility is allowed to earn a "fair rate of return" on its "rate base." (*United States Gypsum, Inc, 2000* quoting *Indiana Gas Co., Inc, 1991)*

[13] The issue of the obligation to serve has recently arisen in the context of large load offerings in the electric industry. (*See e.g., Amazon Data Services, Inc.,* 2025)
[14] Regulators have used the concept of the regulatory compact in making specific findings. *See e.g., In the Matter of the Application of Pinedale Natural Gas, Inc.*, 2015. ("The Commission finds and concludes that…[the utility]…has failed to fully honor the regulatory compact during the past several years.")
[15] Goldberg characterizes the issue this way:

> The administrative contracts approach provides a very different perspective for examining regulator institutions. The "justification" of regulation is seen not to rest on narrow natural monopoly (declining long run average costs) grounds; rather it rests on the long-term relational matters stressed here. Thus, the observed emphasis by regulatory agencies on protection from competition, which appears quite anomalous within the standard framework, has plausible explanation in this broader context… Our approach places a relatively greater emphasis on mechanisms for maintaining, adjusting, and perhaps terminating long term relationships… the emphasis on rights to serve and be served raises natural questions of how, if at all, those rights should be protected. (Goldberg, 1976, p. 445)

[16] Long-term contracts can operate effectively, even in the context of *asset specificity*, when adjustments to the contracts are relatively simple and are agreed to *ex ante*. (Joskow, 1988)
[17] Resistance to the term *regulatory compact* is largely a function of the conclusion that the regulatory contract is not legally enforceable as a contract (i.e., under common law of contracts) or that the term implies a preference for the *status quo*.*(See e.g.,* Peskoe)
[18] While basic duties of the public utility such as the duty to serve are traced to common law precedent. Utilities have, through legislation, *extraordinary* obligations. (Rossi, 1988)
[19] A rate case is a formal administrative process in which the utility provides support for its proposed cost of service and the public, including the regulatory body, is provided the opportunity to scrutinize the data, policy arguments, and any other relevant information. (McDermott. 2012, pp. 12-14)
[20] "The purpose of regulatory policy…is to simulate…the effects of competition and give the consumer the benefits…from a system of competition." (NARUC, 1942, p. 369)
[21] Alternatives to traditional cost-based regulation were in practice from the beginning of regulation. In 1855 a sliding scale, which set prices in an inverse relationship to dividends, was applied to Sheffield Gas in the United Kingdom and by the 1870s the major London companies operated under a revised version of the sliding scale. By the 1930s many gas and electric utilities operated under this approach in the UK. The method was imported for use in the gas industry in Toronto (1887), Massachusetts (1906) and was later applied to Potomac Electric in Washington DC (1925). (Whitten, 1914; Bussing, 1936)
[22] The California Commission stated this as follows:

…the general rate case proceeding is viewed as the embodiment of what is often described as the "regulatory compact." This compact is viewed as a contract between the utility's investors and its customers; as such, it establishes rights, obligations, and benefits for both sides of the bargain:

- Utilities accept the obligation to serve and charge regulated cost-based rates, and customers accept limited entry (i.e., loss of choice) in exchange for protection from monopoly pricing.
- Under this agreement, the utility is provided the opportunity to recover its actual legitimate or prudent costs—determined by a public examination of the utility's outlays—plus a fair return on capital investment as measured by the cost of obtaining capital in a competitive capital market.
- Investors will only provide capital for provision of utility services if they anticipate obtaining a return that is consistent with returns they might expect from employing their capital in an alternative use with similar risk;
- Customers will only accept utility rates if they perceive that the rates fairly compensate the utility for its costs, but are not excessive as a result of the utility taking advantage of its privileged position.

It is the role of regulatory bodies such as this Commission to ensure that both sides fulfill their respective obligations under this bargain. Given the vastly different resources at the disposal of the utilities and their customers, it is up to the Commission to maintain the balance in outcomes between customers and shareholders. This somewhat theoretical construct becomes very real when the Commission fulfills its responsibility and quantifies this balanced outcome in its decisions in general rate cases. (*Order Instituting Rulemaking*, CPUC, 2020, pp. 10-11)

[23] The discussion of revenue requirement draws on an earlier set of publications. (McDermott, 2012; McDermott, Peterson, and Hemphill, 2006)
[24] Economists refer to the opportunity cost of capital as the *normal* profit. Regulators refer this as the fair rate of return. Economists view the opportunity cost of capital as a cost of doing business and do not consider this cost a profit. This is often called the zero-profit level and is associated with profit levels in the long run under pure competition.
[25] The matching principle

…is a fundamental concept of both accounting and ratemaking. A mismatch of reported costs and revenues on an income statement will understate or overstate a firm's earnings. A mismatch of costs and revenues in the calculation of a utility's test year earnings and its revenue requirement will result in deficient or excessive rates- in either case such rates would not be just and reasonable. (*Iowa Public Service Co*. 1982)

[26] *Chicago & Grand Trunk Ry*, 1892. (Authority to set rates encompasses the authority to disallow costs.)
[27] *Northern States Power Company*, 1941 ("Petitioner insists further that the order invades the field of management. We cannot attribute to it such significance. It merely carries to completion the statutory duty of finding the cost of construction by directing petitioner to enter upon its books the determined cost. This is not management; it is regulation by the Commission contemplated by the act. The grant of a license, being a privilege from the sovereign, can be justified only on the theory of resulting benefit to the public.")

[28] The filed rate doctrine prohibits a regulated entity from charging rates other than those lawfully approved by the regulator which is enforced by the prohibition on retroactive ratemaking limiting the regulator to making rates on a prospective basis. (*See* e.g., Watkiss, 1988)
[29] The Virginia Corporation Commission, in approving escalator clauses, colorfully rejected the notion that such clauses removed regulatory oversight noting that the utilities "will still be under the thumb of the commission, and, to vary slightly the picturesque metaphor suggested by counsel for one of the objectors, that thumb will not be amputated." (*Re Lynchburg Gas Company*, 1954)
[30] FERC has explicitly recognized a policy toward recovery of abandonment costs with respect to electric transmission development. (*Promoting Transmission Investment through Pricing Reform*, 2006)
[31] The National Association of Railroad and Utility Commissioners (NARUC) Committee on Public Utility Rates stated in its 1957 annual report:

> Renewed inflation and the increased cost of money revive the necessity of adopting a forward looking view in the fixing of utility rates. Your committee has several times reviewed methods used by commissions to meet these problems. We do not propose to review these methods again in detail but do wish to make one comment. Regulatory methods have of necessity been "backward looking" rather than anticipatory or forward looking in technique. This is easily understandable since the necessity for firm justification of the rates requires firm basic data. However, your committee feels that in view of the above recent economic changes, "backward looking" methods must, to the extent possible, be coordinated with principles founded upon anticipatory views. (Quoted in *Mountain States Tel. & Tel. Co.,*1958)

[32] The Maine Commission stated the issue this way:

> Because rates are set prospectively for an indeterminate future period, it is necessary to normalize expenditures and revenues in the test year to reflect the level of expenditures and revenues that can be reasonably expected to occur during the period that rates are in effect. This process includes incorporating known changes that have occurred since the test year. In addition, this commission in recent years has given consideration to the phenomenon of attrition, in order to take into account expected but not actually known future changes in revenues and expenditures, to determine whether the opportunity to earn the allowed or required rate of return can be maintained for at least the first full year of the period that the new rates are in effect. When measurable attrition can be found, this commission has provided an attrition allowance to compensate for it. (*Re Bangor Hydro-Electric Company*, 1982)